COAL

NEW COAL TECHNOLOGY AND ELECTRIC POWER DEVELOPMENT

K. Morgan MacRae

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K. MORGAN MACRAE

New Coal Technology and Electric
Power Development

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Preface

As a consequence of the paucity of information associated with the costs and impacts in the ongoing discussion of stricter emissions standards, CERI's Board of Directors approved the undertaking of an assessment of the costs, commercial status and potential role of new coal technologies in reducing SO_2, NO_x, and CO_2 emissions. It was anticipated that the study would assist energy/environment policy deliberations in Canada.

Equally important, a publicly available research report which dispelled some of the more common public misunderstandings about coal's current and expected role in electric power generation was called for. So was born this applied research project.

I would like to acknowledge the assistance of the project Advisory Committee--a group of experts who gave freely of their time and constructive criticism so that the author's mistakes and technical oversights could be corrected, thereby ensuring a more cogent report. The Advisory Committee comprised experts from sixteen organizations representing industry, government and academia in both Canada and the United States.

Special thanks are due to the Institute's word processing/graphics section (Beverly Kovacs, Shawna Braun and Megan Murphy) and to the staff of the I.N. McKinnon Memorial Library. Finally, my thanks to Tony Reinsch of the Institute and Dr. Norbert Berkowitz, Professor Emeritus, University of Alberta for their careful review and insightful comments.

I hope that you find this study to be of some particular interest to you. CERI is undertaking further analyses of electric power policy issues and trusts that it can rely on your continued support and commentary to ensure pertinent and practical assessments of energy policy and programs.

Executive Summary

NEW COAL TECHNOLOGY AND ELECTRIC POWER DEVELOPMENT

Preamble

New coal technologies hold considerable promise for improved electrical generating efficiency in an environmentally responsible manner. However, most studies do not compare these technologies with conventional electric power technologies, such as hydro and nuclear, in a consistent framework which accounts for how all might contribute to meeting Canada's future electric power demand.

The objective of this study is to examine the cost of meeting proposed reductions in carbon dioxide (CO_2), sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and evaluate how new coal technologies contribute to reducing these emissions in the Canadian electric power sector.

An important ancillary focus is an examination of the regional implications on electric power production and technology mix. In effect, we set out to determine the least-cost technology mix required to meet Canada's future demand for electricity under constraints imposed by domestic and international concerns with the environment.

This report summarizes work undertaken by the Canadian Energy Research Institute (CERI) in recognition of expressed public concern with the environment and the need to dispel some common misunderstandings about the current and future impact of coal in Canadian electric power production.

Research Objective

The environmental impact of hydrocarbon combustion has become a key topic of discussion in Canadian newspapers, boardrooms and government departments across Canada and in many regions of the world. The production of emissions from fossil fuel applications and their environmental impacts are focussing increased interest and research on more effective ways of both producing and consuming energy.

Coal combustion is cited as a significant cause of world-wide atmospheric pollution, and this concern is promoting increased research and development (R&D) of new, clean coal technologies which reduce emissions that contribute to both acid rain and global warming.

In an effort to reduce acid gas emissions, Canadian and international demonstrations of new, clean coal technologies have proven some technologies commercially viable, and others are expected to be commercially proven within the next decade. These new technologies and processes offer significant improvements in emission control of acid gases and hold potential for lower costs than conventional coal-fired power plants fitted with flue gas desulphurization (FGD) and NO_x control systems.

In the last two years, the Canadian government has moved rapidly in response to growing concern over environmental issues. Public concern for the environment has prompted several initiatives, most notably the Green Plan, and more stringent regulations of emissions are imminent. But, new legislation will have to balance costs against calls for stricter controls in the face of a stagnating economy and higher tax levels. As electric power generation constitutes more than 85 percent of total Canadian coal consumption, stricter emissions regulations could greatly affect Canada's future generation mix and the cost of electricity production.

This study examines the potential development of new clean coal technologies and their impacts on reducing atmospheric emissions of gases which contribute to acid rain, ozone and global warming. The study's goal is to provide government, industry and the Canadian public with an objective, independent assessment of the costs, commercial status and potential contribution of new coal technologies to reducing SO_2, NO_x and CO_2 emissions from the Canadian electric power sector. An ancillary objective is to examine the avoided costs of demand-side programs and their emissions impact by region across Canada.

Planning for Uncertainty

The size and timing of additions to Canadian generating capacity and the ability of utilities to respond to increasingly stringent environmental regulations will depend, first and foremost, on future electricity demand across Canada. Demand forecasts are a crucial planning tool for utilities. Uncertainty regarding proposed changes in environmental legislation complicates the forecasting of electricity demand and determination of the least-cost supply mix needed to economically meet the electricity requirements of Canadians.

To deal with this uncertainty, electric utility planning strategies are increasingly focussed on ways to maximize flexibility in electricity supply and the ability to respond to unexpected developments in demand growth. These efforts include:

- reducing the time-lag between the decision to proceed with a new capacity addition and the in-service date of the new facility;
- streamlining the regulatory and planning processes;
- utilizing generating facilities (such as combined cycle plants or natural gas-fired units) that take considerably less time to construct than large hydroelectric stations and nuclear power plants;
- lobbying government to undertake **quality** analyses of the impacts and costs of new regulations so that Canada's economy is not adversely affected by legislation which places Canadians at a comparative disadvantage in the world economy; and
- improving public and media dialogue to facilitate new utility expansion.

Electric utilities in some regions are also evaluating the enhanced flexibility of greater reliance on demand-side management (DSM), interregional electricity trade and non-utility generation (NUG). Ontario, Quebec and British Columbia, for example, are initiating demand-side programs designed to offset a major percentage of their forecast supply requirements.

Coal's Strategic Role

Canada's current use of coal for electric power production, coupled with Canada's vast coal reserves and the need for significant additions to electrical generating capacity, underscore coal's strategic importance to powering the future electricity requirements of Canadian business and households. In a technology context, coal is of further strategic importance as Canadian research directed to more efficient and more environmentally friendly coal combustion offers considerable export opportunities to developing countries because they will rely on coal to a large degree for their future electric power needs. These factors aside, public concern with the environment dictates that coal be used wisely and more efficiently if it is to continue to play an important role in lighting the homes, offices and industries of Canadians.

Environmental Concerns and Initiatives

The combustion of fossil fuels ranks second as a source of electricity generation in Canada and produces significant atmospheric emissions of SO_2, NO_x, and CO_2. Growing public awareness of how these emissions contribute to acid rain, global warming and the deterioration of local air quality has become the driving force behind interest in greater energy efficiency and Canada-wide government examination of more stringent emissions regulations. Regulations enacted to control emissions will affect the operation and utilization of existing fossil-fuelled generating stations, have an important bearing on technologies deployed in Canadian electric power generation, impact the demand for electricity, and exacerbate planning uncertainty for Canadian electric utilities.

While significant reductions in SO_2 and NO_x emissions from Canadian electric power production may be costly, they are technically attainable. However, efforts to reduce the growth in CO_2 emissions will be considerably more difficult--reduced growth in energy demand, fuel switching and greater energy efficiency are the only known means of achieving a major reduction in the growth of global CO_2 emissions.

Adding to the complexity in controlling CO_2 growth is the fact that the pattern of CO_2 emissions is shifting to those regions of the world which will be financially hard pressed to initiate reduction strategies. Developing countries are expected to account for almost 60 percent of the world's manmade CO_2 emissions by the middle of the next century, compared to their current 20 percent share.

As Canada accounts for only 2 percent of total world CO_2 emissions, Canadian efforts to reduce its emissions will have an inconsequential impact on world-wide carbon dioxide levels. Multilateral actions involving the United States, U.S.S.R, China, Western Europe and the developing countries are mandatory if a reduction in CO_2 and other greenhouse gases is to be accomplished.

Although Canada's emissions are negligible, significant study is underway here to reduce CO_2 emissions. After extensive analysis, Canada's Task Force on Energy and the Environment recommended that a 20 percent reduction in CO_2 was premature, and that the prudent course of action would be to first stabilize and then eventually reduce carbon dioxide levels. In December, 1990 Canada's Green Plan was released, committing the Government of Canada to $3 billion over five years in new funding for the environment. This commitment was subsequently extended to six years in the 1991 federal budget.

Canada's electric utilities are also examining ways to reduce CO_2 emissions. Increased use of demand-side management and conservation programs, electricity trade, non-utility generation, more efficient power production technologies (e.g., integrated gasification combined cycle (IGCC)) and CO_2 recovery and disposal are under investigation to limit the growth in CO_2, as well as SO_2 and NO_x. Recently, one of the federal government's research agencies, the Canada Centre for Mineral and Energy Technology (CANMET), signed a $3 million, five-year agreement with the Canadian Electrical Association to jointly examine the development and commercialization of furnace and boiler processes aimed at reducing greenhouse and acid gas emissions. CANMET is also actively involved in integrated energy efficiency (IEE) programs.

Emission Control Technologies

Over the last decade, technologies for the control of emissions from coal have progressed considerably with improvements in coal-cleaning processes, advances in fuel combustion, and in the cleaning of exhaust gases after combustion. The term **clean coal technologies** is commonly used to refer to this set of new systems and processes that produce fewer air pollutants than conventional combustion methods. As CO_2 emissions have only recently become of concern, technological developments have largely been focussed on control of particulates, SO_2 and NO_x.

Control of pollutants released in the combustion of coal can be achieved in several ways:

- Particulate emissions can be captured after combustion by electrostatic precipitators and bag filter systems.
- Sulphur dioxide emissions can be reduced prior to combustion by switching to low-sulphur fuels or by

removing sulphur from the coal (e.g., by coal washing or coal gasification); during combustion; or after combustion by treating the flue gas.

- Nitrogen oxide emissions can be reduced by combustion modification techniques or, following combustion, by flue gas treatment devices.

Proven technologies available to reduce SO_2 emissions from smelters, power plants and other sources have been applied or are expected to be implemented within Canada in a few years. By 1994, state-of-the-art technologies will be in place in Canadian non-ferrous smelters. Flue gas desulphurization scrubbers (wet limestone type) are planned at several electric power plants. In Ontario, between two and twelve coal-fired units will be retrofitted depending on load growth, while in New Brunswick, new coal-fired units with scrubbers are planned and one is now under construction at Belledune.

While these control technologies will play a significant role, particularly for existing plants, they impose an energy penalty and pose other environmental problems, such as sludge disposal and water contamination. In the longer term, new control technologies which permit simultaneous treatment of SO_2 and NO_x, such as the copper oxide process, may replace conventional scrubbers if current R&D programs prove to be successful. However, the need to address issues such as SO_2 in conjunction with other environmental concerns such as NO_x and CO_2 means that in the long run, new, more energy-efficient production technologies will replace the conventional plants.

Major advances in NO_x control technologies are in use in Japan, Germany and California. However, some of the most promising technologies require further research, development and demonstration with Canadian fuels under Canadian conditions.

Of the various options for controlling emissions (pre-combustion, combustion and post-combustion), combustion technologies present the greatest opportunities for increases in thermal efficiency and net reductions in CO_2 and other radiative gas emissions. Owing to the fact that coal-fired electrical plants are in the order of 35 percent energy efficient, every percentage improvement in efficiency has a leveraged impact on the reduction of emissions. Many of these advanced generation technologies also result in significantly improved methods of controlling SO_2 and NO_x emissions.

Advanced Generation Technologies

World-wide research by the electric power, chemical and coal industries has led to the development of a range of combustion technologies which mitigate the environmental impacts of burning coal for electric power generation--atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC) and IGCC. Of these technologies, IGCC promises the best combination of economic, efficiency and environmental benefits and has been identified by many electric utilities as **the** coal-based power generation technology for the 1990s. Almost all the sulphur (99 percent) can be removed and produced in a saleable molten form. Nitrogen oxide emissions are extremely low at around 25 percent of conventional coal-fired plants. Low NO_x burners under development for gas turbines will lower NO_x emissions further.

Integrated gasification combined cycle offers a combination of advantages which no other coal-based system can match. Integrated gasification combined cycle provides short lead-time construction, competitive capital cost, operational and planning flexibility, lower water consumption, small land requirements, and markedly reduced sulphur, nitrogen, particulate and CO_2 emissions relative to conventional coal-fired power plants. Ongoing progress in gas turbine technology promises further gains in IGCC efficiency. System improvements stemming from IGCC demonstration projects currently being built, together with those resulting from pilot-scale research, portend additional improvements in efficiency, lower costs and major reductions in CO_2 emissions. Moreover, IGCC affords a unique opportunity for co-producing valuable chemical by-products.

As a result of these benefits, interest in IGCC utility applications is growing world-wide. In California, Texaco plans to have a commercial plant producing electricity from a mixture of 75 percent coal and 25 percent sewage sludge from Los Angeles by 1992. Materials such as contaminated soils, waste oils, and refinery wastes can also be easily disposed of due to the higher temperatures at which gasifiers operate. The first commercial IGCC unit to come on-line in Europe is a 250-MW plant scheduled for completion in 1993 at Buggenum, Holland. Germany is planning to have a 150-MW IGCC unit in commercial operation by 1994.

Within Canada, IGCC is under active investigation in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta. The Coal

Association of Canada (CAC) has proposed a unique IGCC demonstration project which would evaluate CO_2 removal and disposal options such as enhanced oil recovery.

Fuel Cells and Magnetohydrodynamics (MHD)

Two technologies under development which offer considerable, longer-term promise for electric power production are fuels cells and MHD.

A fuel cell is a device in which hydrogen, obtained by reforming natural gas, methanol, or coal-derived gas, reacts electrochemically with oxygen to generate electric power. The power generation efficiency of a fuel cell is high, some 40 to 60 percent, and these efficiency levels are maintained even under partial load operation. Waste heat recovery from fuel cell operations may yield total energy efficiencies of up to 85 percent where waste heat is used for domestic hot water, space heating, or low-level process heat for industrial uses. Owing to their energy efficiency relative to conventional generating units, fuel cells offer a significant reduction in CO_2 emissions.

Fuel cells in capacities suitable for electric power plant use are unlikely to have been demonstrated in long-term operation much before the end of the century. The first commercial use is expected to occur in decentralized power generation and in load levelling applications.

While fuel cells are currently uneconomic, owing to their high capital cost, this situation will improve through continued R&D and eventual mass production. Financial credits stemming from their modularity, relative independence of efficiency on size and load, dispersibility and rapid installation time also reduce the effective capital costs.

Magnetohydrodynamics is a direct burning, high efficiency, advanced fossil fuel technology for generating baseload electric power. While this technology holds considerable promise in terms of its efficiency and environmental performance, it is not expected to be commercially available for electric utilities until after the turn of the century.

It is anticipated that first generation MHD power plants will have efficiencies of 40 to 50 percent and mature plant efficiencies of 60 percent. This increase in efficiency compared to conventional coal-fired plants means less fuel use, less energy for fuel transportation, less mining/reclamation, less cooling water and lower overall plant effluents for each kW.h of electricity generated.

Magnetohydrodynamics is in the development stage--its maturity, potential applicability and economics have not been established and there are drawbacks which must be overcome before it becomes a viable supply option for electric power production. It is very capital intensive, requires superconductors that have only reached the laboratory stage of development, and the high temperature combustion could result in high nitrogen oxide emission rates. Despite these drawbacks, MHD affords significant potential for high efficiency and low emissions for electric power utilities beyond the turn of the century.

CO_2 Strategy Overview

While new coal combustion technologies offer considerable potential for increased energy efficiency and reductions in atmospheric emissions and waste product streams, broadly-based strategies for controlling emissions will also be required to mitigate pollution problems caused by the growing electric power requirements of Canadians. As actions taken to reduce CO_2 also reduce sulphur dioxides, nitrogen oxides and waste by-products such as FGD sludge, it is instructive to review some of the strategies postulated for CO_2 reduction.

End-Use Efficiency

Significant opportunities for end-use efficiency gains in the electricity sector include the development and application of products, services and techniques such as: (1) energy efficient space heating and cooling systems; (2) insulation; (3) energy efficient windows and doors; and (4) energy efficient lighting, motive power and air handling systems. In Ontario, for example, DSM programs are expected to meet 60 percent of all growth in electricity demand over the next ten years. If these planning targets are met, savings in electricity consumption will result in an impressive reduction in annual emissions--52 kt of NO_x and 20.6 Mt of CO_2 by 2005.

Integrated Energy Efficiency

Widespread adoption of cogeneration systems could yield enormous savings in fossil fuels, presently used for space heating and for the production of electricity for air conditioning, resulting in a dramatic reduction in atmospheric pollution. Actions called for to ensure that the benefits of cogeneration are properly accounted for include:

(1) planning electric power plants with combined heat and power as part of the siting conditions, to ensure that the waste heat can be used effectively; and

(2) encouraging municipalities to evaluate cogeneration opportunities, especially where new housing and commercial building projects are planned.

Shifting Fuels

A shift to hydrogen-rich fuels would involve much greater use of natural gas. However, a concern with the increased use of natural gas for Canadian electric power generation is the relative price of gas compared to coal over the next twenty years.

An attractive fuel-shifting option gaining increasing support in the United States and Europe is the use of municipal waste as a source of power. Municipal solid waste is the source of many pollutants and its effective disposal is becoming increasingly difficult and expensive. Moreover, waste landfill sites are a major source of methane emissions, a greenhouse gas which is 25 to 30 times more "efficient" than CO_2. Advanced combustion techniques, such as fluidized bed combustion or IGCC, offer the best options for rendering these wastes sterile, eliminating methane emissions associated with landfill and reducing solids disposal. At the same time, the significant amounts of energy inherent in the waste streams can be utilized.

CO_2 Scrubbing and Disposal

Collection and disposal of CO_2 from existing electrical generating units is economically unattractive. Local applications, such as enhanced oil recovery using CO_2 from an IGCC water shift process may, however, ultimately prove economic.

Switching to Non-Fossil Energy

Prospects for combined cycle plants based on coal gasification and fuel cells seem a more promising, and more timely alternative than investing in nuclear power for western Canada. Research, development and demonstration applied to western coal utilization will, moreover, have export potential to coal-hungry developing countries, whereas foreign orders for CANDU technology have been disheartening.

Increased Electricity Trade

Opportunities exist for greater interregional electricity trade in North America. While most of this trade would flow south to the United States, due to greater revenues accruing to electricity exports, the point is a moot one. If Canadian electricity exports reduce SO_2 and NO_x emissions from U.S. power plants, which would otherwise fall on eastern and central Canada, then all parties benefit.

Greater synergies within Canada's utility system also bear examination. Greater interregional trade within Canada--e.g., from British Columbia to Alberta and from Labrador to New Brunswick--could also reduce the growth of harmful atmospheric emissions of Canadian SO_2, NO_x and CO_2.

Afforestation

Afforestation appears to be the least expensive CO_2 sequestering technique under consideration and is obviously an important component of any overall policy thrust designed for CO_2 abatement.

Technology Transfer

It is clearly in the interests of industrialized countries to assist developing countries with greenhouse gas mitigation. This suggests that the transfer of Canadian energy-efficient technologies and research programs to the developing world should be an important part of Canada's strategy to mitigate the growth in CO_2 and other greenhouse gases. This argument supports greater funding for development of energy efficient coal technologies in Canada and transfer of this technology to: (1) developing countries in Asia; and (2) environmentally backward countries in eastern Europe and the Soviet Union.

Limiting World-Wide Population Growth

One obvious means to control the growth in the world's production of greenhouse gases is reducing population growth. However, virtually all discussion on greenhouse gas abatement is directed to the supply side and virtually none to the intrinsic cause of the growth in greenhouse gases--the world's burgeoning population and its energy demands.

Policies aimed at reducing the growth in population projected for developing countries are mandatory if we are to successfully reduce the growth in greenhouse gases. This is another area where technology transfer from developed to developing countries has merit.

Adapting to Global Warming

As our capability to model the regional implications of global warming improves, various other options could become cost-effective abatement strategies:

- staggering work hours to minimize congestion of our highways and peak use of electricity for lighting and cooking;
- encouraging responsible employees to work at home to reduce peak hour pressures on urban highways and mass transit systems;
- mandating a reduction in packaging of consumer products, thereby reducing energy used for packaging and reducing the number of trees required to sequester CO_2;
- banning production and delivery of junk mail and telephone books (paper constitutes 35 percent of landfill) and/or examining the use of such combustibles for electricity generation in city centres;
- evaluating planning practices that push future urban development away from rising lake and ocean water levels;
- increasing inner-city parking charges to encourage multi-passenger trips and use of mass transit;
- raising gasoline and diesel taxes to promote the production and purchase of energy efficient automobiles and trucks--with the tax revenue earmarked for cleaning up existing environmental problems and financing research and demonstration of new, more energy efficient technology; and
- restricting non-essential passenger cars from the inner city.

Various methods to reduce CO_2 emissions exist and the cost effectiveness of these alternatives must be compared to determine an optimum strategy for CO_2 emission reduction in both the short and long term. In the short term, energy conservation, cogeneration and afforestation appear more economic than CO_2 recovery and disposal systems. The development of fuel cells and sale of Canadian clean coal technology to developing countries are strong contenders for CO_2 mitigation in the medium to long term.

Closing the Gap--Strategies for New Coal Technologies

An electricity generation planning model (ELGEM), jointly developed by CERI and the Alberta Research Council, was used to assess the cost of Canadian electric power and regional emissions impact for SO_2, NO_x and CO_2 under six different cases:

(1) Reference case: existing SO_2 controls only, per Canada's Acid Rain Control program;

(2) Base case: existing SO_2 controls plus suggested NO_x target reductions;

(3) Demand-side management/Conservation case: electricity demand reduced by 20 percent from base case levels by 2009;

(4) Coal technology costs: 15 percent reduction in the installed capital cost of IGCC, PFBC and AFBC relative to base case levels;

(5) Coal technology efficiency gain: 10 percent (absolute) gain in energy efficiency for IGCC, PFBC and AFBC relative to base case efficiencies; and

(6) No nuclear constraints: no moratorium on nuclear power development in Ontario.

In order to account for the net impact of changes in NO_x regulations, and the impact of those regulations on the cost of Canadian electric power generation, the SO_2 case was first subtracted from the SO_2/NO_x case. In order to meet suggested reductions in NO_x emissions, the present-value cost of Canada-wide electricity generation would rise by $2.98 billion over the 1988-2011 period. This translates to a cost of $1443 per tonne for acid gas removal.

As the implementation of NO_x controls similar to those suggested in the recent NO_x/VOC Draft Management Plan seemed imminent, this scenario (SO_2/NO_x case) is used as the basis of comparison for the remaining scenarios evaluated in ELGEM. Again, to show the net impact on the present-value cost of Canadian electric power generation and the resulting reduction in Canada-wide SO_2,

NO_x and CO_2 emissions, the SO_2/NO_x case is subtracted from each of these scenarios. Summary results depicting these net impacts are displayed in Table 1.

As shown in this table, demand-side programs are the most cost-effective means of making a major reduction in total emissions. Relative to the base case, savings in the present value cost of Canadian electric power generation total $166 billion and cumulative emissions are reduced by 803 Mt for the 1988-2011 period relative to the base case. While the ELGEM model does not currently account for DSM/Conservation supply curves, the model was used to infer an opportunity cost (or shadow price) for emissions reduction. Using the reduction in emissions and savings in the cost of power, these results suggest that demand-side programs costing less than $207.45 per tonne offset should be cost effective for Canada as a whole.

Unconstrained development of nuclear power follows, with savings relative to base case levels of $1.8 billion and associated emissions reductions of 180 Mt for the 1988-2011 period. Improving the energy efficiency of clean coal technologies, such as integrated gasification combined cycle, follows closely with savings in the cost of Canadian power of $1.5 billion and emissions savings of 126 Mt over the 1988-2011 period. Reducing the capital cost of new coal technologies follows with savings in the cost of Canadian electric power of $0.9 billion, but emissions reductions for the 1988-2011 period of only 11 Mt.

While these results support popular assessments undertaken to date, it is important to note that the ELGEM results presented above assume that a tonne of NO_x, SO_2 or CO_2 is equally harmful to the environment. However, given that CO_2 accounts for over 99 percent of total emissions from Canadian electric power production, these results could more accurately be thought of as representative costs to reduce CO_2 emissions from Canadian electric power production.

While it is exceedingly difficult to assess the relative impact of SO_2, NO_x and CO_2 emissions on the environment and the economy, such a comparison is important for the determination of the funds to be assigned and for the design of programs to be undertaken to reduce emissions. For example, if we could support the fact that a tonne of CO_2 was only 1/15 as harmful to the environment as acid rain, then increasing the efficiency of IGCC and nuclear power would be equal in terms of their relative costs and emissions reduction potential. It is

TABLE 1

SUMMARY RESULTS
INCREMENTAL COST AND EMISSIONS SAVINGS[a]

Scenario	CO_2 (Mt/yr)	SO_2 (Mt/yr)	NO_x (Mt/yr)	Total (Mt/yr)	Change in Objective Function (million $1989 Cdn)	Hurdle Price[b] ($1989 Cdn/tonne)
DSM/Conservation	799.8	1.8	1.0	802.6	166,501	207.45
Lower Capital Cost	9.0	0.9	0.6	10.6	903	85.22
Higher Coal Efficiency	124.5	0.8	0.6	126.0	1,482	11.76
No Nuclear Constraints	180.9	(0.4)	(0.03)	180.5	1,765	9.78

SOURCE: Canadian Energy Research Institute.

[a] Net reduction in emissions and present value costs relative to the base case scenario.

[b] The hurdle price can be interpreted as the **maximum** dollar per tonne expenditure which can be justified in achieving the targetted reductions in emissions, under the various scenarios.

interesting to note that, even at this 1/15 ratio, CO_2 emissions still comprise over 85 percent of total emissions from Canadian electric power production.

All technologies--DSM, clean coal technologies and nuclear power--will play a part in reducing atmospheric emissions from Canadian electricity production. Improving the efficiency of integrated gasification combined cycle has a major impact on reducing emissions from Canadian electric power production. While DSM/conservation programs have the most dramatic impact, the question of cost and deliverability bear important consideration. Fortunately, the implementation of DSM/conservation programs is starting to take place in Canada. These actions will help to determine the most cost-effective demand-side programs together with the most effective mix of complimentary technologies--hydro, nuclear and fossil-fuelled.

Recommendations

- R&D of clean coal technologies for use in Canadian electric power production should be increased and export of Canadian-based, clean coal technology to developing countries should be evaluated.

- Electric utilities should be allowed to include demand-side programs and competitive bidding programs into utility rate base.

- Public Utilities Boards' regulatory powers should be changed to recognize energy efficiency in electricity production and use, not simply rates and rate structures.

- Government should undertake quality analyses of the impacts and costs of new regulations to ensure that such new regulatory requirements do not put Canadian industry and services at a comparative disadvantage in the world economy.

- Canadian public and government spokesmen must recognize the strategic importance of coal to fuelling the electric power needs of Canadian business, industry and residences. Coal constitutes over 80 percent of Canada's remaining fossil-fuel reserves; coal can be used cleanly; and the price of coal is directly tied to production costs, not geopolitical events. Changes in regulatory practices and development of new clean coal technologies will be required to ensure that coal benefits Canadian society without causing detrimental impacts to the environment.

- Significantly more R&D funding support should go to research, development and demonstration of integrated energy efficiency programs, which include burnable waste for energy.

- Given the considerable importance of Canada's municipal governments to planning for atmospheric emissions reductions, these organizations should be more actively involved in Canadian energy/environmental policy and policy initiatives.

- The use of IGCC burning coal and sewage sludge, akin to plans for the Cool Water Plant, should be evaluated by Canadian energy/environment policy makers--an integrated approach to energy and environment is mandatory.

- Research and demonstration of fuel cells by Canadian businesses and industry should be actively supported.

Chapter 1

INTRODUCTION

The production of greenhouse gases stemming from fossil fuel use and their effect on the environment have renewed interest and research on deployment of more effective ways of producing and conserving energy. A key component of this interest centres on new coal technologies, as coal has been cited as a significant cause of world-wide carbon dioxide (CO_2) emissions. Energy demand growth in newly industrialized countries, the expected reliance within these countries on coal for electricity production, and technology transfer from developed to developing regions are further incentives for increased interest in clean coal technologies. Greenhouse warming is an issue which goes beyond national borders. The transfer of more efficient energy production technologies from developed to developing countries could greatly help to stem the growth in world-wide CO_2 emissions.

As electric power generation constitutes more than 85 percent of total Canadian coal consumption, environmental strategies premised upon increasing public concern with atmospheric emissions of greenhouse gases could greatly affect the use of coal, Canada's future generation mix, and the cost of electricity production. **In recognition of the potential impacts of more stringent environmental controls, this study examines the potential development of new clean coal technologies and their impacts on reducing atmospheric emissions of trace gases which cause acid rain, ozone and global warming.**

The development of new combustion technologies is directed towards: (1) the control of particulates during combustion; (2) the control of sulphur dioxide (SO_2) and nitrogen oxides (NO_x); (3) minimization of CO_2 emissions; and (4) more efficient electricity production. Control of particulates is largely an issue of refinements to existing process technologies, focussing on more complete combustion and the refinement of particulate traps.

Treatment of flue gases using glue gas desulphurization (FGD) is an established and widely used technology. New, more cost-effective processes are being developed to control SO_2 in response to concern over the high costs and large volume of wastes associated with current FGD systems. Other options for reducing acid gas emissions include greater use of low sulphur coals and new, emerging coal combustion technologies. The success of Canadian and international demonstration projects has made several of these technologies commercially viable and several others are expected to be proven so within the next decade or so. These new technologies offer significant improvements in emission control and the potential for lower costs than conventional coal-fired plants fitted with FGD.

In addition to the acid gases which can now be controlled, CO_2 is the other major gaseous emission of coal combustion. Carbon dioxide, methane, nitrous oxide, chlorofluorocarbons (CFCs), and forest clearing and burning have been identified as the major contributors to global warming. Nitrogen oxides, together with volatile organic compounds (VOCs), have also been identified as a major contributor to enhanced ozone levels which adversely affect human health and agricultural productivity. Some research suggests that the increasing level of CO_2 is causing an overall warming trend in the earth's climate and that potential environmental impacts warrant immediate action. Studies are underway world-wide to confirm climate warming and international protocols seeking limits on greenhouse gas emissions are under review. Canada is viewed as a leader in the drive to establish an international protocol for CO_2 emissions and is actively participating at the national and international level in the examination of ways to reduce CO_2 and other greenhouse gas emissions.

Public concern with environmental issues has prompted a large number of initiatives and more stringent emission controls seem imminent--dependent upon costs and public support of harsher controls in the face of concern with the economy and higher tax levels. Proposed environmental controls will further accentuate this burden, yet the Canadian public appears ready to support tighter control on emissions which are adversely altering Canada's environment.

In order to assess the implications of stronger emissions controls and their impact on Canada's electric power sector, the Canadian Energy Research Institute (CERI) set out to examine the implications of suggested target levels for three effluents of major concern--SO_2, NO_x and CO_2. While control strategies for SO_2 and NO_x do not necessarily impact on CO_2 emissions, there are instances where this is the case and we believed it important that all three emissions be assessed in a common context. **It is also important that this assessment evaluate "new coal technologies" in a**

setting where competing electric power technologies such as hydro and nuclear power are also included and evaluated against projected levels of Canadian electric power demand. Refinement of a Canadian generation planning model (ELGEM) jointly developed by CERI and the Alberta Research Council (ARC) allowed us to undertake this evaluation.

Our intent in this study is to examine the cost of meeting proposed reductions in SO_2, NO_x and CO_2 emissions and to evaluate in this setting how new coal technologies might evolve. Our objective is to provide policy makers and the Canadian public with an objective and independent assessment of the potential costs and commercial status of new coal technologies and their contribution to reducing SO_2, NO_x and CO_2 in the Canadian electric power sector.

An important ancillary focus is an examination of the regional implications for electric power production and technology mix. In effect, we set out to determine the least-cost technology mix required to meet Canada's future demand for electricity under constraints imposed by domestic and international concerns with the environment.

1.1 Study Outline

To set the stage for the comparative economic assessment of new coal technologies, a brief overview of expected capacity additions and the importance of coal to Canadian electric power production is presented. A discussion of environmental concerns and initiatives follows this, and introduces our description of a number of promising new coal technologies. This is in turn followed by a review of alternative strategies to limit emissions and the presentation of a number of scenarios which explore the cost and emission effectiveness of new coal technologies in the context of future deployment of hydroelectric and nuclear power by region across Canada. The study's conclusions and recommendations complete the report.

Chapter 2

ELECTRICITY DEMAND - UNCERTAIN REQUIREMENTS

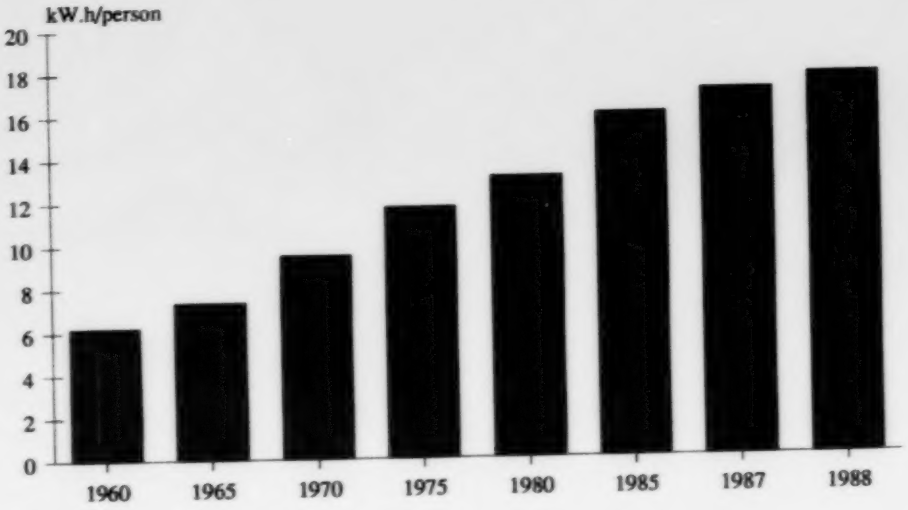
2.1 Introduction

The size and timing of additions to Canadian generating capacity and the ability of utilities to respond to concerns about environmental quality will depend to a large extent on the future course of electricity demand in Canada. Demand forecasts are a crucial ingredient in the development plans of utilities, but uncertainty regarding future trends in electricity consumption considerably complicates the planning process. Most utilities are cautious in their present demand forecasting efforts, due to their experience of the 1970s when overly-optimistic demand expectations motivated them to plan and complete new capacity at a record rate, only to be surprised by the slowdown in electricity demand in the early 1980s. This slowdown left many utilities with significant amounts of excess capacity--a situation all utilities are determined to avoid.

2.2 The Composition of Electricity Demand

Electricity is a convenient, flexible and relatively inexpensive form of energy that has become essential to a myriad of human activities. The use of electricity for so many different purposes in so many sectors of our society makes it especially difficult to evaluate the likely trend of electricity demand in the coming decades (see Figure 2.1). The analysis is further complicated by the fact that the relationship between electricity supply and demand has been, and will continue to be, a complex, two-way interdependence. Early electricity supply developments were intended to meet a rather narrowly defined and specialized need: lighting, transportation (electric railways and streetcars) and certain power applications in the larger North American cities at the turn of the century. The emerging and increasingly efficient technology of electricity supply which developed in response to this demand, however, soon sparked new uses for electricity--such as electrochemical smelting and refining processes, a variety of thermal industrial applications, and eventually home heating, electronics, and

Figure 2.1
Per Capita Electricity Consumption
Canada, 1960-1988



SOURCE: Electric Power in Canada,
EMR Canada, 1989.

other uses. This unpredictable evolution of electricity demand continues to unfold and complicate the future supply planning strategies of utilities.

In the industrial sector, technological change will exert a mixed and unpredictable effect upon electricity demand in the coming years. On the one hand, improvements to both energy efficiency and to general manufacturing productivity will restrain electricity demand. Conversely, new production techniques may increase electricity consumption, even though they result in a net decrease in overall energy consumption.[1]

In the residential sector, population growth is expected to slow in coming decades, reducing the rate of formation of new households. This combined with general improvements to household energy efficiency--resulting from better insulation and more efficient refrigerators, water heaters and other major appliances--will restrain growth in electrical energy consumption. However, other forces are at work--the increasing popularity of air conditioners and continuing growth in personal incomes--which could maintain demand growth rates in the residential sector at relatively high levels.

In Canada's commercial sector, demand growth is equally unpredictable. On the one hand, service industries are expected to increasingly dominate Canada's economy; the electronics revolution could further boost this sector's electricity requirements. On the other hand, many untapped conservation opportunities exist which could restrain demand growth, especially if demand-side management (DSM) programs are aggressively implemented by Canadian electric utilities.

2.3 The Uncertainty of Electricity Demand

Electricity demand in Canada is being pulled by two general but competing forces. In one direction, Canada's economy as a whole has become more **energy efficient** in recent years. This tendency will continue, motivated by economic, environmental and technological forces. Pulling in the opposite direction, Canada's economy has become more **electricity intensive**. New technology often promotes energy efficiency, but in many circumstances it also contributes to this growth in electricity intensity. The implications are that Canada's economy will become more electricity intensive in the coming decades.[2]

To deal with this uncertainty and minimize impacts on their existing customer base, utility planning strategies are increasingly focussed on ways to maximize the **flexibility** of electricity supply and its ability to respond to unpredicted demand developments. These efforts include:

- reducing the time-lag between the decision to proceed with a new capacity addition and the in-service date of the new facility;
- streamlining the regulatory and planning processes;
- utilizing generating facilities (such as combined cycle plants or natural gas-fired units) that take considerably less time to construct than large hydroelectric stations and nuclear power plants; and
- improving public and media dialogue to facilitate new utility expansion.

Utilities are also evaluating the opportunities afforded by greater interregional electricity trade as well as greater reliance on DSM and non-utility generation.

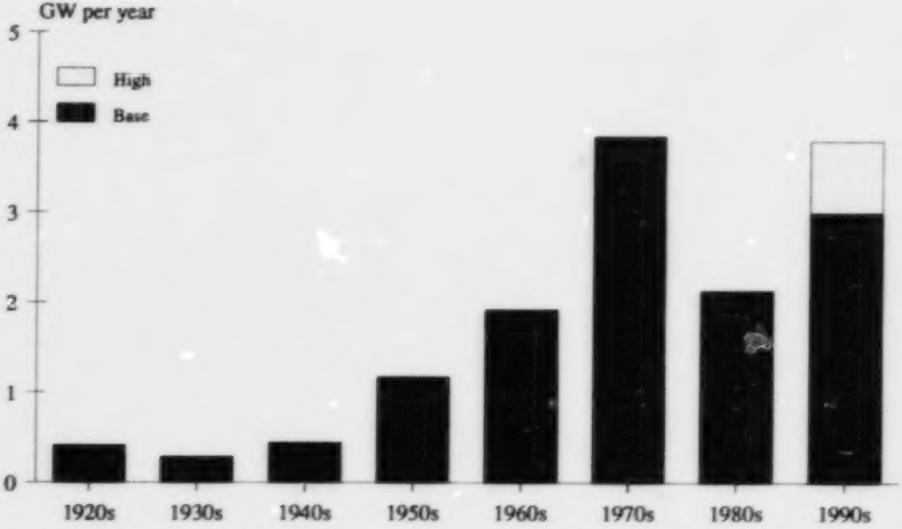
While utilities strive to expand their options and thereby increase their flexibility, the environment looms as a major factor exacerbating planning uncertainty and decisions on the proper mix of new supply technologies. Environmental pressures will affect the end-use of electricity, as processes are changed to minimize environmental impacts, and this in turn will impact the total demand for electricity.

2.4 Illustrative Capacity Additions

In late 1989, the Canadian Energy Research Institute (CERI) released a report entitled *Critical Issues in Electric Power Planning in the 1990s*. Among other considerations, this study dealt with illustrative electrical generating capacity requirements for Canada.

Assuming a Canada-wide average growth rate of 2.4 percent per year in electricity demand, the analysis concluded that some 9200 MW of new capacity would be required by the end of the century. When added to the 14 500 MW of capacity to be brought on-stream from already committed projects, this results in a requirement for over 23 700 MW of new electrical generating capacity in Canada by the year

Figure 2.2
Yearly Capacity Additions
Canada, 1920s - 1990s



SOURCE: EMR Canada.

2000. Assuming a reasonable, but somewhat higher growth rate (3.5 percent) yielded an estimate of total capacity requirements of over 37 000 MW by the end of the century.[3,4]

Although there is only a moderate difference between these demand scenarios, a **slight** increase in demand growth rates is magnified into a **substantial** differential in terms of absolute future capacity requirements. As illustrated in Figure 2.2, the base demand scenario (including firm export opportunities) would result in the addition of some 3000 MW of new capacity per year between now and the year 2000--more than in any period of Canadian history, with the exception of the 1970s. If, on the other hand, demand growth were to follow the higher scenario, average increases in new capacity of almost 4000 MW per year would be required--a significant challenge given our historical additions to generating capacity.[5]

While forecast uncertainties prevail, the potential magnitude of these additions to electrical generating capacity underlines the importance of enhanced planning flexibility in order to deal with unexpected demand developments. The task of planning for and containing atmospheric emissions against this backdrop of uncertain but potentially significant additions to electrical generating capacity will be extremely difficult--a combination of both demand- and supply-side options will be required. Public calls for stricter environmental controls, particularly for coal-fired generation, exacerbate planning uncertainty and the emphasis on greater efficiency in the production and end-use of electric power. New, more efficient and more flexible technologies/strategies which reduce environmental impacts are fundamental and are under development by utilities, the coal industry and research and development agencies across Canada.

Footnotes

[1] See Merete Heggelund, *Industrial Natural Gas Demand*, CERI Study No. 30 (Calgary, Alberta: Canadian Energy Research Institute, May 1989).

[2] See International Energy Agency, *Electricity End-Use Efficiency*, (Paris, France: Organisation for Economic Co-operation and Development/IEA, 1989).

[3] These estimates are based on domestic demand growth only, and do not include capacity that would be required to meet potential firm export contracts.

[4] For a detailed description of how these forecasts were derived see K. Morgan MacRae, "Future Capacity Additions," Chapter 2, *Critical Issues in Electric Power Planning in the 1990s*, Volume I, CERI Study No. 33 (Calgary, Alberta: Canadian Energy Research Institute, November 1989).

[5] Recent electric utility forecasts published by the Electric Power Branch of Energy, Mines and Resources Canada show load growth corresponding to an average increase of 2000 MW per year to the turn of the century.

Chapter 3

THE STRATEGIC IMPORTANCE OF COAL

Having briefly examined the potential but uncertain prospects for future electrical generating capacity, we now turn to discuss coal's contribution to Canadian electric power.

Coal consumption in power generation totalled 45 926 kt in 1989 or 85.2 percent of total Canadian consumption. The steel industry accounted for 11 percent of total consumption and various other categories were responsible for the residual 4 percent of total consumption. As a percentage of total Canadian coal consumption, Canada's electric power sector has grown significantly over the past decade--from 72 percent in 1979 to over 85 percent in 1989 (see Table 3.1). Domestically produced coal is also far more important today than it was a decade ago for producing electric power (see Table 3.2 and Figure 3.1); imported coal now accounts for less than 19 percent of total coal used in Canada's electric power sector.

While coal for Canadian electric power production has grown by over 80 percent in the last ten years, its use is highly regionalized. Three provinces--Alberta (46.6 percent), Ontario (27.9 percent) and Saskatchewan (18.6 percent)--account for the bulk (93 percent) of total coal consumed for electric power production (see Table 3.3). However, in a relative sense, coal is a significant source of power for both the eastern provinces and in western Canada (see Tables 3.4 and 3.5). Of the total electric energy produced in 1989, coal-fired generation provided 55 percent of total electricity production in Prince Edward Island; 60 percent in Nova Scotia; 79 percent in Alberta; 73 percent in Saskatchewan; and 24 percent in Ontario.

Although coal is regionally important as a fuel for the production of electric power, it figures somewhat less prominently in terms of total Canadian generating capacity--coal comprised about 18 percent of total Canadian electrical energy production in 1989. In the international context, Canada's use of coal for electricity generation is also minor, owing to our reliance on hydroelectric power which represented 60 percent of Canadian electricity production and over 57 percent of installed generating capacity in 1989 (see Figure 3.2).

TABLE 3.1

COAL CONSUMPTION BY MARKET

	Power Generation		Steel Industry		Other Uses		
Year	Kilotonnes	Market Share	Kilotonnes	Market Share	Kilotonnes	Market Share	Total Consumption
1979	24 961	71.8	7 865	22.6	1 937	5.6	34 763
1980	27 782	74.4	7 241	19.4	2 310	6.2	37 333
1981	29 813	77.7	6 377	16.6	2 177	5.7	38 367
1982	33 655	81.1	5 576	13.4	2 246	5.4	41 477
1983	36 216	83.0	5 583	12.8	1 850	4.2	43 649
1984	40 208	82.6	6 542	13.4	1 949	4.0	48 699
1985	40 396	83.0	6 262	12.9	1 998	4.1	48 656
1986	36 394	81.7	6 134	13.8	2 030	4.6	44 558
1987	41 825	83.4	6 309	12.6	2 010	4.0	50 144
1988	45 978	84.5	6 263	11.5	2 149	4.0	54 390
1989	45 926	85.2	5 917	11.0	2 038	3.8	53 881

SOURCE: Energy, Mines and Resources Canada, *Statistical Review of Coal in Canada, 1989*.

TABLE 3.2

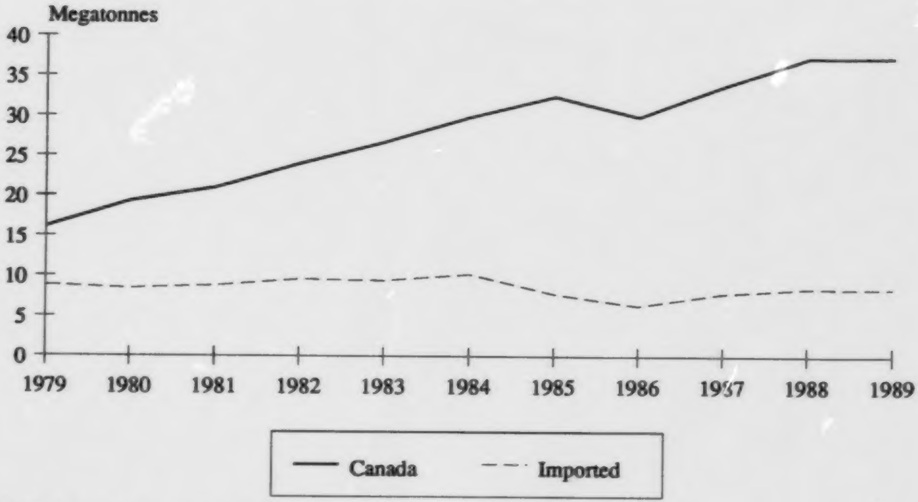
COAL CONSUMPTION BY ORIGIN FOR POWER GENERATION (kilotonnes)

Year	Canada	Percent	Imported	Percent	Total
1979	16 104	64.5	8 857	35.5	24 961
1980	19 314	69.5	8 468	30.5	27 782
1981	20 998	70.4	8 815	29.6	29 813
1982	24 033	71.4	9 623	28.6	33 656
1983	26 748	73.9	9 468	26.1	36 216
1984	29 935	74.5	10 273	25.5	40 208
1985	32 563	80.6	7 833	19.4	40 396
1986	30 035	82.5	6 359	17.5	36 394
1987	33 932	81.1	7 893	18.9	41 825
1988	37 451	81.5	8 527	18.5	45 978
1989	37 449	81.5	8 477	18.5	45 926

SOURCE: Energy, Mines and Resources Canada, *Statistical Review of Coal in Canada, 1989*.

Figure 3.1

Coal Consumption by Origin for Power Generation, 1979-1989



SOURCE: Energy, Mines and Resources Canada, Statistical Review of Coal in Canada, 1989.

TABLE 3.3

COAL CONSUMED FOR POWER GENERATION BY PROVINCE
(kilotonnes)

	Nova Scotia	New Brunswick	Ontario	Manitoba	Saskatchewan	Alberta	Total Canada
1979	645	198	9 906	73	4 956	9 183	24 961
1980	1 052	315	10 779	240	4 972	10 424	27 782
1981	1 126	515	11 460	332	4 935	11 445	29 813
1982	1 300	548	12 484	185	5 897	13 242	33 656
1983	1 400	564	13 025	109	6 625	14 492	36 215
1984	1 974	610	13 413	163	7 925	16 123	40 208
1985	2 235	521	10 985	253	8 290	18 112	40 396
1986	2 137	469	9 172	111	6 786	17 719	36 394
1987	2 077	526	12 016	457	7 672	19 077	41 825
1988	2 266	678	13 079	780	8 637	20 538	45 978
1989	2 141	705	12 809	327	8 534	21 410	45 926

SOURCE: Energy, Mines and Resources Canada, *Statistical Review of Coal in Canada, 1989.*

TABLE 3.4

ELECTRICAL ENERGY PRODUCTION BY FUEL TYPE, 1989
(gigawatt-hours)

Province	Coal	Oil	Natural Gas	Total Fossil Fuels	Nuclear	Hydro	Other	Total
Newfoundland	0	2 032	0	2 032	0	32 832	0	34 864
P.E.I.	129	104	0	233	0	0	0	233
Nova Scotia	5 481	2 589	0	8 070	0	939	159	9 168
New Brunswick	1 629	7 932	0	9 561	5 269	2 361	269	17 460
Quebec	0	1 619	0	1 619	4 820	138 409	0	144 848
Ontario	34 020	1 455	1 793	37 268	65 261	38 625	283	141 437
Manitoba	378	0	9	387	0	18 300	54	18 741
Saskatchewan	9 797	14	656	10 467	0	2 832	202	13 501
Alberta	34 146	120	6 899	41 165	0	1 598	572	43 335
B.C.	0	303	4 977	5 280	0	51 088	1 293	57 661
Yukon	0	35	0	35	0	405	0	440
N.W.T.	0	210	0	210	0	260	0	470
Canada	85 580	16 413	14 334	116 327	75 350	287 649	2 832	482 158

SOURCE: Energy, Mines and Resources Canada, *Electric Power in Canada, 1989*.

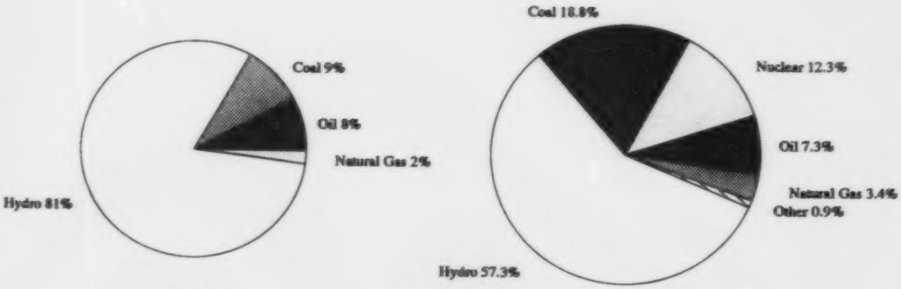
TABLE 3.5

PRINCIPAL COAL-FIRED POWER PLANTS IN CANADA FOR 1988

Province		Plant	Coal Type	Capacity (MW)	Coal Consumption (kt)
Nova Scotia	1	Seaboard	Bituminous	96	151
	2	Maccan	Bituminous	15	18
	3	Trenton	Bituminous	210	285
	4	Lingan	Bituminous	633	1 358
	5	Point Tupper	Bituminous	229	329
New Brunswick	6	Dalhousie	Bituminous	200	476
	7	Grand Lake	Bituminous	85	198
	8	Chatham	Bituminous	32	31
Ontario	9	Lakeview	Bituminous	2 400	2 005
	10	Nanticoke	Bituminous	4 000	6 080
	11	Lambton	Bituminous	2 000	2 924
	12	Thunder Bay	Lignite	400	1 041
	13	Atikokan	Lignite	206	759
Manitoba	14	Selkirk	Lignite	132	30
	15	Brandon	Lignite	237	297
Saskatchewan	16	Estevan	Lignite	65	221
	17	Boundry Dam	Lignite	875	4 274
	18	Poplar River	Lignite	592	4 028
	19	Queen Elizabeth	Lignite	232	11
Alberta	20	Battle River	Sub-Bit	740	3 658
	21	H.R. Milner	Bituminous	150	577
	22	Wabamun	Sub-Bit	582	2 875
	23	Sundance	Sub-Bit	2 200	8 949
	24	Keephills	Sub-Bit	806	3 185
	25	Sheerness	Sub-Bit	383	1 506
	26	Genesee	Sub-Bit	400	660

SOURCE: Energy, Mines and Resources Canada, *Statistical Review of Coal in Canada, 1989*.

Figure 3.2
Installed Generating Capacity
by Fuel Type

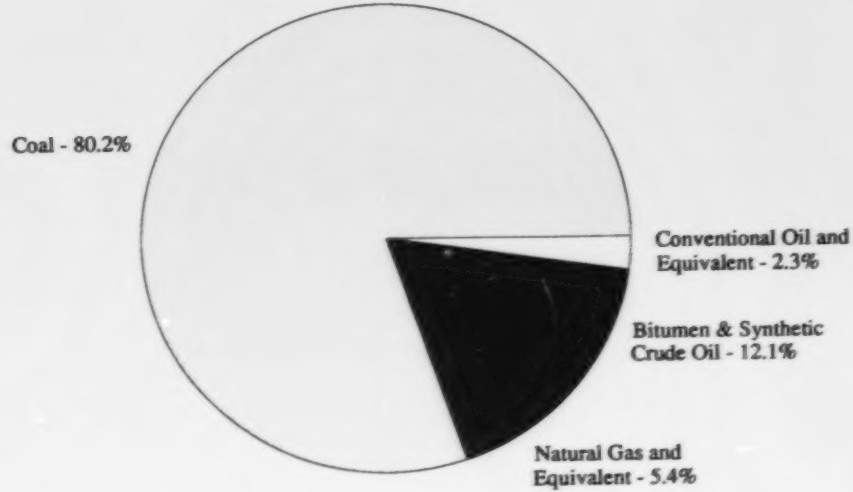


1960
Total Capacity: 23 035 MW

1989
Total Capacity: 102 215 MW

SOURCE: EMR Canada, Electric Power
in Canada, 1989.

Figure 3.3
Canadian Reserves



SOURCE: ERCB, Energy Alberta 1988.

3.1 Canadian Reserves

The strategic importance of Canada's continued use of coal for electric power production is reflected in our vast coal reserves. As shown in Figure 3.3, Canadian coal represents over 80 percent of Canada's remaining fossil-fuel reserves. Reserves of conventional oil and equivalent, natural gas and equivalent and bitumen and synthetic crude oil account, respectively, for 2.3 percent, 5.4 percent and 12.1 percent of total remaining Canadian fossil-fuel reserves as of year-end 1988.[1,2]

The current use of coal for electricity generation, coupled with Canada's vast coal reserves and the potential for significant additions to Canadian generating capacity, underline coal's strategic importance to Canadian electric power generation. However, increasing public concerns with the environment dictate that coal be used wisely and more efficiently if it is to continue to play an important role in Canada's electric power sector. The next chapter of this report reviews some of these general environmental concerns and initiatives before turning to a description of new coal technologies.

Footnotes

[1] Alberta, Energy Resources Conservation Board, *Energy Alberta 1988* (Calgary, Alberta: Energy Resources Conservation Board, 1988), p. 43.

[2] The importance of coal for worldwide electricity generation is borne out in world proven commercial fossil-fuel resources (expressed in terms of 1987 consumption rates): oil, 32 years; natural gas, 59 years; and coal, 226 years. See I.J. Graham-Bryce, "Optimization of Energy Strategies for Power Generation in Relation to Global Climate Change" in *Energy Technologies for Reducing Emissions of Greenhouse Gases: Proceedings of an Expert's Seminar*. Vol. I, April 12-14, 1989. (Paris, France: Organisation for Economic Co-operation and Development/International Energy Agency, 1989) p. 162.

Chapter 4

ENVIRONMENTAL CONCERNS AND INITIATIVES

4.1 Introduction

The production of energy, regardless of the source, has potentially adverse effects on the environment. At the fuel production (or extraction) stage, the mining of coal and uranium and the production of natural gas can temporarily disturb large tracts of land and, in some cases, diminish land use productivity for agriculture, forestry and recreation. In the production of hydro power, large tracts of land are alienated from other potential uses and entire ecosystems disrupted by large-scale flooding. Similarly, the land-intensive nature of commercial development of less conventional forms of energy, such as wind and solar, place further strains on the environment.

At the fuel processing or refining stage, environmental impacts take the form of solid, liquid and gaseous "wastes" or emissions. The refining and manufacturing of nuclear fuels results in the creation of small volumes of extremely toxic and radioactive wastes. The processing of natural gas and the refining of petroleum are responsible for emissions of sulphur oxides, nitrogen oxides and hydrocarbons.

The energy transportation or delivery stage also has environmental impacts. For example, the transportation of liquefied natural gas (LNG) imposes risks to safety, while oil and gas pipelines are also subject to risk of accidental rupture and the associated impacts on the environment. The impact of electromagnetic radiation on human health is also becoming an increasing concern in the context of the high voltage transmission of electric power by overhead lines.

Despite these impacts, however, the greatest current source of concern over the environmental effects of energy production and use relates to the combustion of fossil fuels. The combustion of fossil fuels is the second most important source of electricity generation in Canada and produces significant atmospheric emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and carbon dioxide (CO_2). Growing awareness of the role of these emissions in causing acid rain, global warming and a deterioration of local air quality has centred public attention on this stage of the energy cycle (see Table 4.1). In fact, public awareness of environmental issues has grown to the point where it has become the driving force behind improvements in energy efficiency and government initiatives directed to more stringent control of emissions. The emerging pressures to control emissions will impact the operation and utilization of many of Canada's existing fossil-fuelled generating stations, have an important bearing on the choice of technology deployed in Canada's future generation mix, and exacerbate planning uncertainty for Canadian electric utilities.

4.2 Atmospheric Emissions

Public opinion polls indicate that environmental issues are one of the greatest sources of concern to Canadians today. This concern, and much of the associated response by governments in Canada and in many regions of the world, is focussed on atmospheric pollution. A number of clearly distinguishable sources of concern have been identified, including acid rain, ground level ozone (urban smog) and global warming.

4.2.1 Acid Rain

In Canada, emissions of SO_2 and NO_x produced primarily by metal refining and smelting, and to a lesser degree by the burning of fossil fuels, are primary contributors to acid rain. In the atmosphere, these two forms of "acid gas" form sulphuric and nitric acids which, in turn, are often carried long distances by prevailing winds before falling as acid rain, snow, dust or fog. These wet and dry forms of acid precipitation are collectively referred to as acid rain or, more generally, as acid deposition.

Acid rain is recognized as a potentially serious, long-term air pollution problem for industrialized countries. Acid deposition may increase the acidity of lakes, streams, ground water, and soil, threatening wildlife populations and reducing growth in forests as well as agricultural products. In addition, acid rain erodes buildings and materials and is suspected of contributing to respiratory problems in humans. Over 80 percent of Canadians live in areas with high levels of acid-rain-related pollution.

Acid rain is a "regional" as distinct from a global problem. Because of the nature of wind patterns in North America, more than half of the sulphur deposition in eastern Canada is transported by prevailing winds from sources in the United States. Acid deposition is

TABLE 4.1a

SOURCES AND IMPACTS OF ENVIRONMENTAL PROBLEMS

Problem	Impact	Principal Source
Acid Rain	Acidification of lakes, streams, groundwater and soil. Reduces growth of forests and threatens fish and other wildlife.[a]	Sulphur Dioxide (SO_2) and Nitrogen Oxides (NO_x)
Ground Level Ozone (Urban Smog)	Results in respiratory and other health problems in humans and injures trees, crops and other vegetation.	Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOCs)
Global Warming	Increased global temperature and weather instability, economic and political disruption.	Water Vapour, Carbon Dioxide ($C0_2$), Methane (CH_4), Chlorofluorocarbons (CFCs), Nitrous Oxide (N_2O) and Ozone (O_3)

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

[a] More pronounced in Central Canada due to lack of buffering ability of soils to neutralize acid rain together with the high absolute level of acid gas emissions.

TABLE 4.1b

GREENHOUSE GASES

Gases	Perceived Causes
Carbon Dioxide (CO_2)	Fossil-fuel use, deforestation
Methane (CH_4)	Breakdown of organic matter: - Rice paddies - Wetlands - Livestock
Nitrous Oxide (N_2O)	- Agricultural practices - Fossil-fuel combustion - Natural land emissions
Ozone (O_3)	Volatile organic compound emissions
Chlorofluorocarbons (CFC11, CFC12)	- Cooling applications - Electronics cleaning - Insulating and packaging

SOURCE: Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies," presented to *IEA/OECD Expert Seminar on Energy Technology for Reducing Greenhouse Gases*, Paris, France, April 12-14, 1989, (Palo Alto, California: Electric Power Research Institute).

not as serious a problem in western Canada as it is in the East because of lower overall sulphate loadings, and a more acid-resistant environment.[1] However, the western provinces and federal government are jointly examining critical loadings for western and northern Canada.

4.2.2 Ground Level Ozone

Ozone, often referred to as photochemical or urban smog, is produced in the lower atmosphere from photochemical reactions involving NO_x and volatile organic compounds (VOCs). Because the chemical reactions depend on both sunlight and temperature, ozone concentrations tend to be highest on hot sunny days. In Canada, concern over NO_x and VOC emissions stems from their effects, at elevated concentrations, on human, animal and plant health, and their role in acid deposition and the broader problems of stratospheric ozone depletion and global warming.[2]

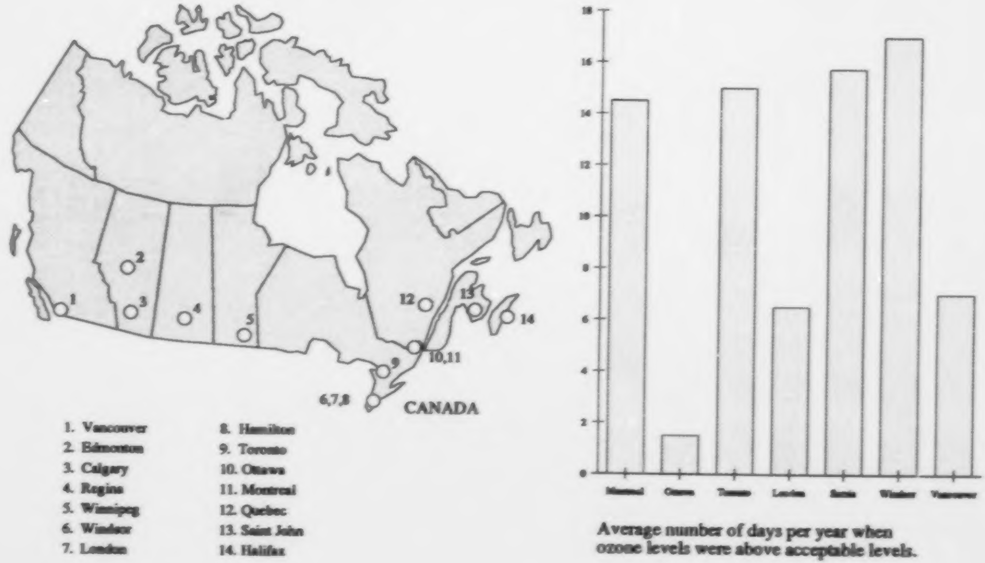
Man-made emissions of NO_x[3] (over 60 percent from transportation) and VOCs, from the combustion of fossil fuels as well as various industrial and commercial processes, have elevated ozone levels in many parts of the country, causing potentially serious health problems. Over half of the Canadian population is regularly exposed to ground level concentrations of ozone known to have adverse health effects. The urban areas in the B.C. Lower Mainland, the Windsor-Quebec City corridor and Saint John, New Brunswick are regions where ozone levels most frequently exceed environmental quality standards (see Figure 4.1).

As with SO_2, these pollutants have a major trans-boundary component, with a significant proportion of Canadian ambient levels originating in the United States and occasionally with Canadian emissions flowing south. The fact that VOCs and NO_x from the central United States contribute significantly to elevated ozone levels in southern Ontario and Quebec has also drawn public attention to this problem.

4.2.3 Trends in Acid Gas Emissions

In Canada, the major sources of SO_2 emissions are non-ferrous metal smelters and to a lesser extent the burning of coal and oil in power plants and other industry applications. In much of south-eastern Canada, a substantial portion of the problem results from the trans-boundary flow of SO_2 from sources in the United States.[4]

Figure 4.1
Areas of Smog Concentrations in Canada



Average number of days per year when ozone levels were above acceptable levels.

SOURCE: Canada's Green Plan.

In the period from 1970 to 1985, SO_2 emissions in Canada declined dramatically from 6.7 Mt to 3.7 Mt, or 45 percent. Most of this reduction took place in Ontario and Quebec, reflecting a concerted effort to control emissions from non-ferrous smelters. Sulphur dioxide emissions have not declined in the Canadian electric utility industry, as SO_2 controls are only now being introduced by some eastern Canadian utilities. Over the 1970-1985 period, emissions from electric utilities increased 47 percent, from 502 kt to 738 kt, and the share of total emissions accounted for by electric power generation rose from 7.5 percent (1970) to 20 percent (1985). However, projections published by Environment Canada indicate that emissions from Canada's electric power sector will fall about 20 percent over the 1985-2005 period (see Table 4.2).

Over the 1970-1985 period, NO_x emissions increased from 1.4 Mt to about 2 Mt, despite the enactment (1977) of emission standards for light-duty vehicles--by far the largest source of NO_x. This increase is largely attributed to: (1) a significant expansion in the total number of vehicles in the period; (2) a significant lag between enactment of vehicle standards and the effects, due to slow vehicle inventory turn-over; and (3) an expansion of other uncontrolled sources, notably fuel combustion. For example, utility emissions increased by 66 percent from 149 kt to 248 kt compared to an increase in total NO_x emissions for the period of 42 percent.[5]

The provincial distribution of SO_2 and NO_x for 1985 is depicted in Figures 4.2 and 4.3 and Table 4.3. In terms of total Canadian SO_2 emissions from electrical utilities in 1985, the most important contributors were Ontario, Nova Scotia, New Brunswick and Alberta. Collectively, these four provinces accounted for over 85 percent of the total SO_2 emissions resulting from Canadian electric power production.

With the exception of Ontario, the regional nature of NO_x emissions by Canada's electrical sector contrasts sharply with that of SO_2. Next to Ontario, which accounts for 40 percent of total emissions, the most important sources of electrical utility emissions are Alberta and Saskatchewan. These three provinces account for about 85 percent of total NO_x emissions from Canada's electric power sector.

Projections by Environment Canada indicate that, without more stringent emissions guidelines, NO_x emissions from Canadian electric power generation will grow by over 40 percent over the next

TABLE 4.2

SULPHUR DIOXIDE:
PROJECTED EMISSIONS IN CANADA BY SECTOR
1985-2005[a]
(kilotonnes)

Sector	1985	1990	1995	2000	2005	Ratio 2005/1985
Transportation	95 (2.6)	103	115	128	147 (4.7)	1.547
Power Generation	738 (19.9)	711	606	633	592 (18.7)	0.802
Fuel Combustion[b]	279 (7.5)	295	291	297	319 (10.1)	1.143
Primary Metals Smelting	1 749 (47.2)	1 610	1 119	1 124	1129 (35.7)	0.646
Oil and Gas[c]	532 (14.4)	444	495	533	566 (17.9)	1.064
Other Industrial[d]	311 (8.4)	307	346	372	408 (12.9)	1.312
Total Canada	3 704 (100.0)	3 470	2 972	3 087	3 161 (100.0)	0.853

SOURCE: Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls - (Draft)* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-71.

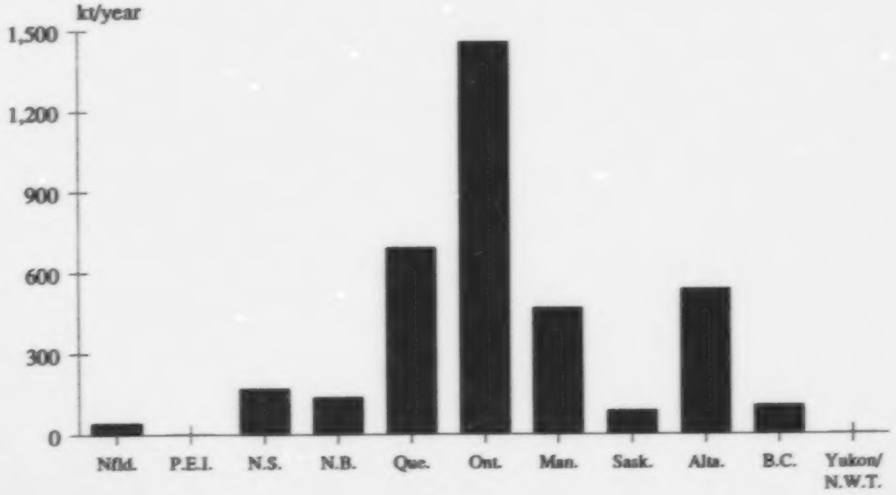
[a] Figures in brackets denote percent of total Canadian emissions.

[b] Fuel Combustion excludes Power Generation.

[c] Oil and Gas includes Tar Sands, Refining and Natural Gas Processing.

[d] Other Industrial includes Iron Ore Mining, Pulp and Paper, Incineration and Miscellaneous other sources.

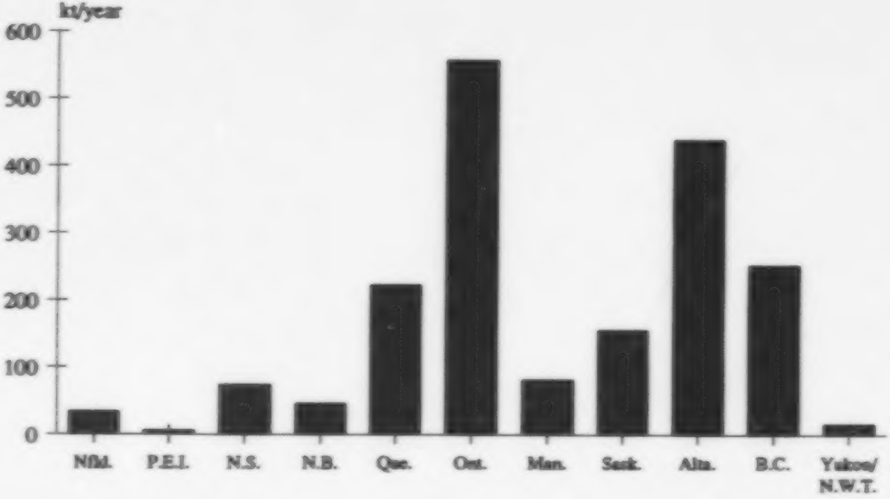
Figure 4.2
Provincial Distribution of SO_2 Emissions
1985



SOURCE: LRTAP Draft Report, February 1990.

Figure 4.3

Provincial Distribution of Nitrogen Oxides Emissions - 1985



SOURCE: LRTAP Draft Report, February 1990.

TABLE 4.3

UTILITY EMISSIONS OF SO_2 AND NO_x BY PROVINCE, 1985

	SO_2			NO_x		
Province	Tonnes	Percent of Total Canadian SO_2 Emissions	Percent of Total Provincial SO_2 Emissions	Tonnes	Percent of Total Canadian NO_x Emissions	Percent of Total Provincial NO_x Emissions
Newfoundland	22 267	3	51	3 808	2	11
P.E.I.	287	0	17	67	0	1
Nova Scotia	129 898	18	76	21 676	9	28
New Brunwick	93 991	13	68	7 929	3	17
Quebec	0	0	0	0	0	0
Ontario	336 707	46	23	94 600	40	16
Manitoba	3 380	0	1	1 781	1	2
Saskatchewan	68 993	9	81	35 773	15	23
Alberta	80 314	11	15	67 810	29	15
B.C.	102	0	0	1 657	1	1
TOTAL	735 939	100	20	235 101	100	12

SOURCE: Environment Canada, *The 1985 Inventory of Common Air Contaminants*, June 1989, Appendix A.

fifteen years, bringing this sector's contribution to total Canadian NO_x emissions to over 18 percent in 2005 (see Table 4.4).[6]

4.2.4 The Greenhouse Effect and Global Warming

Greenhouse gases--mainly water vapour, carbon dioxide, methane, nitrous oxide and chlorofluorocarbons (CFCs)--absorb heat that radiates from the earth's surface and act like a blanket, holding in the heat and warming the climate. Human activities are increasing the atmospheric concentrations of greenhouse gases on a global basis. While the extent and timing of man-induced global warming is very uncertain, there is a growing belief that projected increases in the concentrations of greenhouse gases will alter the world's climate. Over the next fifty years, the buildup in greenhouse gases is projected to increase average world temperatures between 1.5 and 4.5°C. Warming on this scale could have profound impacts--precipitation patterns could change dramatically, the severity and frequency of extreme weather disturbances could increase, and sea levels could rise by as much as 1.5 metres. The most extreme temperature increases would likely occur in the higher latitudes of the Northern Hemisphere during the winter months. These changes would have major effects on Canadian agriculture and water resources.[7]

Although CO_2 is the most important man-made greenhouse gas, it is not the only one (see Figure 4.4). Scientists have detected increases in other, even more potent greenhouse gases, notably CFCs, methane, nitrous oxide and tropospheric ozone. These gases stem from a broad range of sources, such as swamps, fertilizer use, landfill sites, rice paddies and industrial processes. Once emitted, many of these gases persist for very long periods of time and some are growing at rates considerably faster than that of carbon dioxide (see Table 4.5).

While significant reductions in acid rain (SO_2 and NO_x emissions) may be costly, they are technically attainable. However, efforts to curb the growth in CO_2 will be considerably more difficult--reduced growth in energy demand, fuel switching and improved energy efficiency are the only currently known means for achieving a major reduction in global CO_2 emissions.

Adding to the complexity in controlling the problem is the fact that the pattern of emissions is changing to those regions which will be hard pressed to initiate greenhouse gas reduction strategies. Between 1950 and 1980, world-wide emissions of CO_2 more than tripled, with the pattern of global contribution changing in parallel

TABLE 4.4

NITROGEN OXIDES:[a] PROJECTED EMISSIONS IN CANADA BY SECTOR 1985-2005[b] (kilotonnes)

Sector	1985	1990	1995	2000	2005	Ratio 2005/1985
Transportation	1 180 (62.5)	1 122	976	961	1 020 (53.6)	0.864
Power Generation	248 (13.1)	288	319	364	352 (18.5)	1.419
Fuel Combustion[c]	346 (18.3)	350	368	365	357 (18.8)	1.032
Misc. Industrial Process[d]	113 (6.0)	117	133	152	175 (9.2)	1.549
Total Canada	1 887 (100.0)	1 877	1 796	1 842	1 903 (100.0)	1.009

SOURCE: Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls - Draft* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-73.

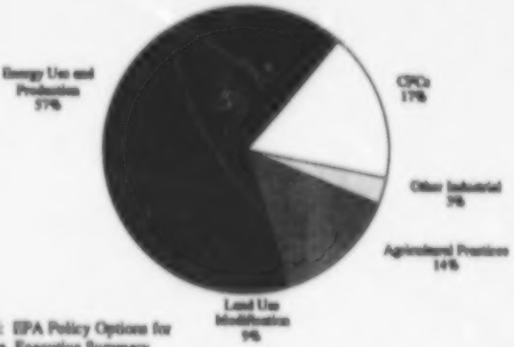
[a] Nitrogen Oxides are expressed as N_2O.

[b] Figures in brackets denote percent of total Canadian emissions.

[c] Fuel Combustion excludes Power Generation but includes Natural Gas Processing.

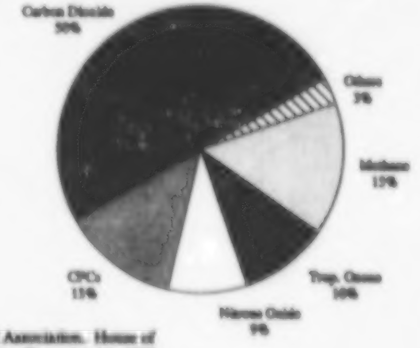
[d] "Miscellaneous Industrial Processes" includes Iron Ore Mining, Pulp and Paper, Incineration, etc.

Figure 4.4a
Activities Contributing to Global Warming



SOURCE: EPA Policy Options for Stabilizing, Executive Summary, February 21, 1989, p. 55.

Figure 4.4b
Radiative Gases and Their Relative Contribution to Global Warming



SOURCE: Coal Association. House of Commons Briefing, December 14, 1989.

TABLE 4.5

MAJOR GREENHOUSE GASES AND THEIR CHARACTERISTICS

Gas	Atmospheric Concentration (ppm)	Annual Increase (%)	Relative Greenhouse Efficiency (CO_2=1)	Current Greenhouse Contribution (%)	Principal Sources of Gas
Carbon Dioxide (Fossil Fuels)	351.3	0.4	1	57 (44)	Coal, Oil, Natural Gas
(Biological)				(13)	Deforestation
Chlorofluoro-carbons	0.000225	5	15,000	25	Foams, Aerosols Refrigerants, Solvents
Methane	1.675	1	25	12	Wetlands, Rice Fossil Fuels, Livestock
Nitrous Oxide	0.31	0.2	230	6	Fossil Fuels, Fertilizers, Deforestation

SOURCE: Christopher Flavin, *Slowing Global Warming: A Worldwide Strategy* (Washington, D.C.: The Worldwatch Institute, 1989), p. 13.

with the growth of industrialization. North America and western Europe together accounted for 68 percent of global CO_2 in 1950 but represented only about 43 percent of the total thirty years later. In contrast, the portion attributable to the People's Republic of China and developing countries in Africa, Latin America and southern Asia grew from 7 percent to over 20 percent of the world total.[8] Over the period to 2005, the rate of growth in emissions is projected to be slowest in the Organization for Economic Co-operation and Development (OECD) countries (1.2 percent per year) as compared to developing countries (3.7 percent per year).

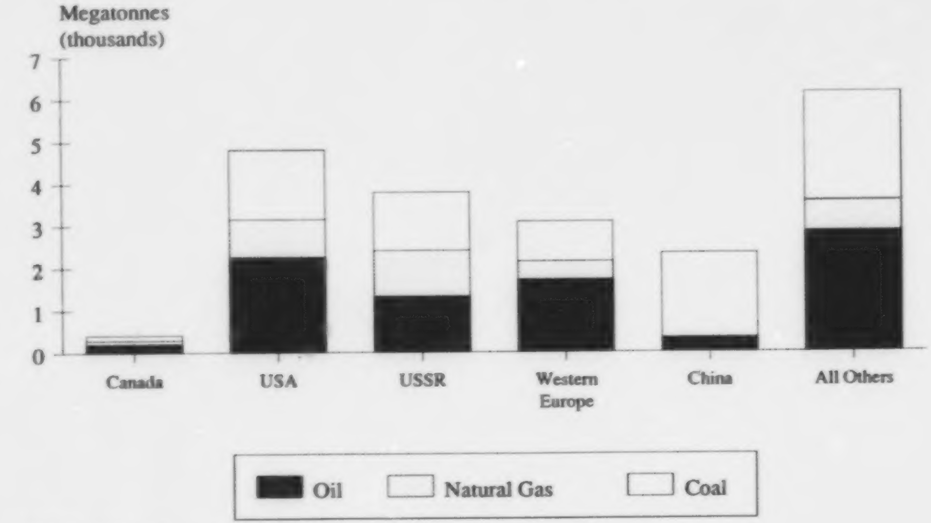
Given these trends, the developing countries are expected to account for almost 60 percent of the world's man-made CO_2 emissions by the middle of the next century. As a result, stabilization and reduction of global emissions cannot be achieved by any one region acting unilaterally. Multilateral actions involving the United States, U.S.S.R, China, western Europe, and the developing countries will be required to curb greenhouse gas emissions (see Figures 4.5 and 4.6).

In the global context, Canada's total emissions are small, though our per capita emissions are high (see Figure 4.7). Canada's current contribution to global CO_2 emissions is estimated at only 2 percent, due in large part to our dependence on hydroelectric power for electricity generation (see Figure 4.8).

Table 4.6 shows estimated CO_2 emissions from fossil-fired power plants in Canada for 1988. Alberta, owing to its dependence on coal, accounted for 38 Mt of total emissions followed by Ontario at 31 Mt and Saskatchewan at 13 Mt. Current projections indicate that Canadian man-made emissions of CO_2 could increase by about 50 percent over the next 15 years (see Figure 4.9). Carbon dioxide emissions from the electric power sector, which account currently for 20 to 25 percent of energy-related CO_2 emissions in Canada, are projected to more than double by 2005 (see Figure 4.10).[9]

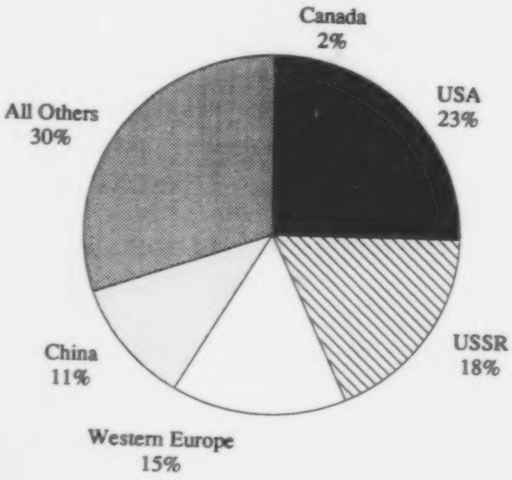
While the full impacts of acid rain, ground level ozone and global warming are not completely understood, they are potentially enormous. Increasing pressure is therefore being exerted on those sectors whose emissions contribute significantly to these problems. This has significant implications for all energy producers and consumers, including the electric power industry.

Figure 4.5
1987 International Carbon Dioxide
Emission Estimates



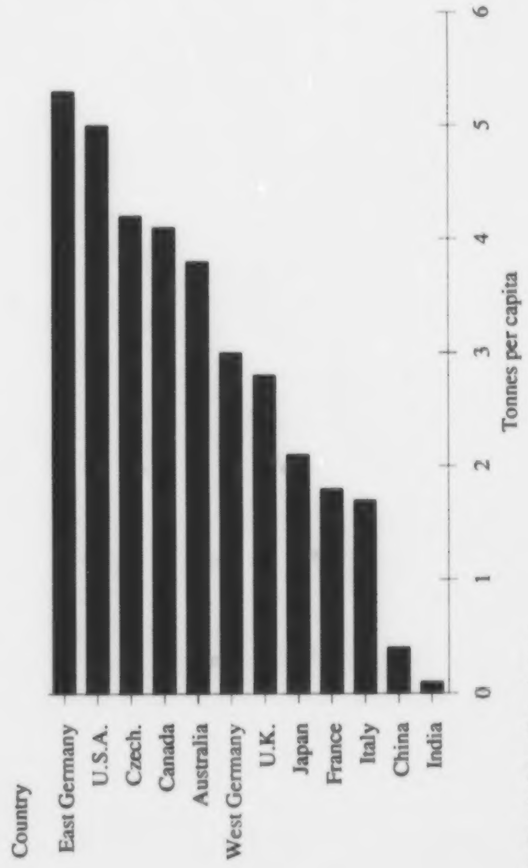
SOURCE: Alberta Energy, June 1989, p. 27.

Figure 4.6
Contribution to Energy Related CO_2
by Country, 1987



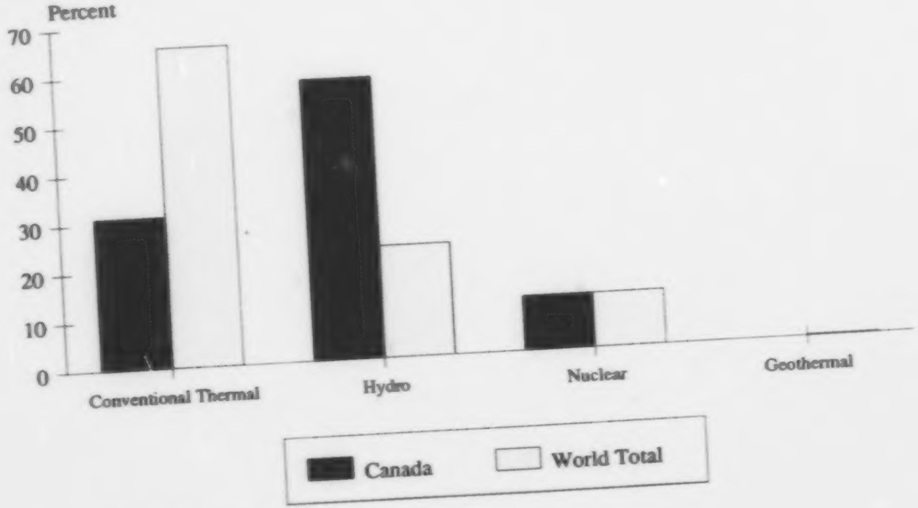
SOURCE: I. Burn, Alberta Energy,
June 1, 1989.

Figure 4.7
Fossil Fuel CO_2 Production, 1986
(per capita)



SOURCE: Ontario Select Committee on Energy, Interim Report, April 1990.

Figure 4.8
International Comparison of Installed Generating Capacity, 1986



SOURCE: EMR Canada, Electric Power in Canada 1988, p. 7.

TABLE 4.6a

CO_2 FROM FOSSIL FUELS USED FOR ELECTRIC POWER GENERATION, 1988[a]

(kilotonnes)

	Canadian Coals			
Province	Bit.	Sub-Bit.	Lignite	Imported Bit.
Newfoundland	0	0	0	0
P.E.I.	0	0	0	0
Nova Scotia	5 349	0	0	77
New Brunswick	1 494	0	0	135
Quebec	0	0	0	0
Ontario	6 139	0	3 034	21 042
Manitoba	0	0	1 142	0
Saskatchewan	0	0	12 646	0
Alberta	1 649	35 152	0	0
B.C.	0	0	0	0
Yukon & N.W.T.	0	0	0	0
Canada (Mt)	15	35	17	21

TABLE 4.6b

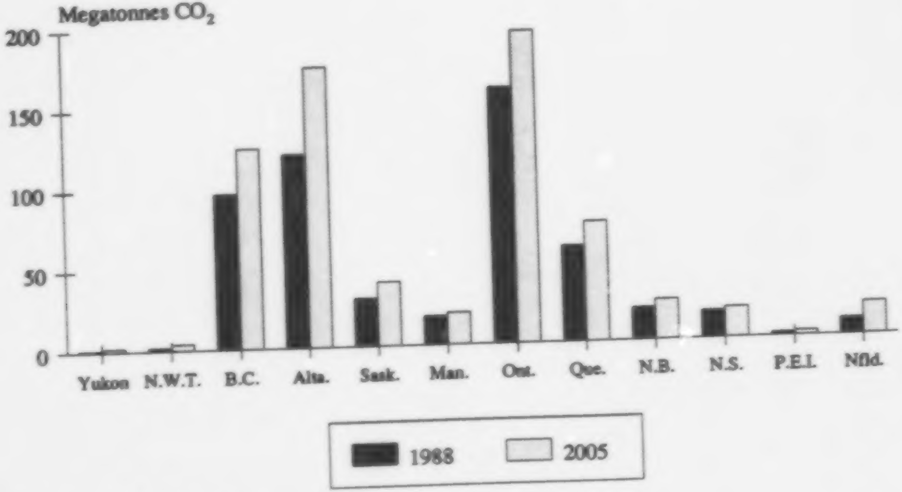
CO_2 FROM FOSSIL FUELS USED FOR ELECTRIC POWER GENERATION, 1988[a]

Province	Gas (kt)	Diesel Fuel Oil (kt)	Light Fuel Oil (kt)	Heavy Fuel Oil (kt)	Total (Mt)
Newfoundland	0	89	5	1 091	1.2
P.E.I.	0	9	0	103	0.1
Nova Scotia	0	30	6	1 146	6.6
New Brunswick	0	4	6	3 967	5.6
Quebec	0	78	121	147	0.3
Ontario	0	0	44	364	30.6
Manitoba	1	19	1	0	1.2
Saskatchewan	275	8	0	1	12.9
Alberta	1 500	11	0	0	38.3
B.C.	60	118	0	0	0.2
Yukon & N.W.T.	0	181	0	0	0.2
Canada (Mt)	2	1	0	7	97.2

SOURCE: Canadian Energy Research Institute, based on data from Statistics Canada 57-003 and A. P. Jacques, *National Inventory of Sources and Emissions of Carbon Dioxide*, Environment Canada, 1989.

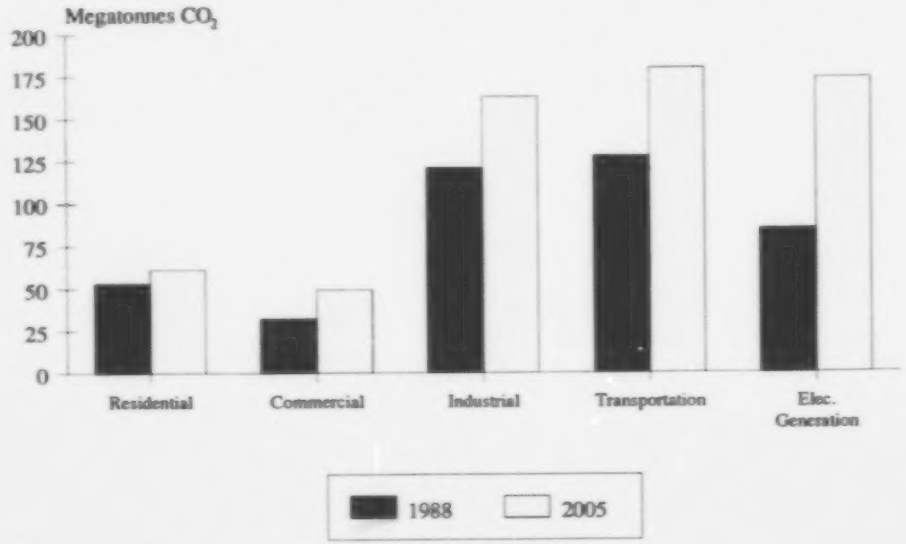
[a] Accounts for combustion only.

Figure 4.9
Carbon Dioxide Emissions by Province and Territory



SOURCE: Report of the Federal/Provincial/Territorial Task Force on Energy and the Environment, April 1990.

Figure 4.10
Projected Carbon Dioxide Emissions
by Sector



SOURCE: DPA Group Inc.

4.3 Initiatives to Limit Atmospheric Emissions

Environmental quality is a shared responsibility of the federal and provincial governments in Canada. The provincial governments are responsible for intraprovincial environmental matters, while the federal government is responsible for environmental issues that are interprovincial or international in scope. In practice, this allocation of responsibility has meant that the Canadian government has authority for regulating emissions from mobile sources, while the provinces retain the primary authority for regulating stationary sources such as electric power plants.

As a result of the interregional and international dimensions of acid rain, elevated ozone, and global warming, the federal government has taken the lead role in designing/evaluating control initiatives for a wide variety of atmospheric emissions. Over the coming decade, international agreements entered into by the federal government will likely prove a driving force behind more stringent provincial regulation of electric utility emissions.

The first in a series of recent initiatives to control emissions of SO_2, NO_x and VOCs occurred in Geneva in 1979, when the Canadian federal government became party to the United Nations Economic Commission for Europe (UNECE) Convention on Long Range Transboundary Air Pollution (LRTAP). The Convention encouraged countries to reduce pollution, including trans-boundary pollution, and succeeded in laying the foundation for future protocols which contain specific emission reduction targets for SO_2 and NO_x.

4.3.1 Sulphur Dioxide

In 1985, under the 1979 LRTAP Convention, Canada signed an SO_2 Protocol whereby participants agreed to reduce their national annual sulphur emissions, or their trans-boundary fluxes, by at least 30 percent (from 1980 levels) by 1993. Canada and the other signatories to the Protocol also agreed to examine the need for further SO_2 reductions as environmental conditions might warrant.

In order to meet Canada's obligations under this protocol, the federal government put in place the Canadian Acid Rain Control Program which is focussed on the seven eastern provinces (Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland). Under federal-provincial agreements these provinces adopted targets for a reduction in combined SO_2 emissions from roughly 4.5 million tonnes in 1980 to 2.3 million tonnes in 1994. The control measures established by these provinces are expected to result in attainment of the 1994 SO_2 objectives and reduced SO_2 emissions until the turn of the century. Under the Federal Government's Green Plan, acid rain-related emissions in eastern Canada beyond 1994 will be capped through extended federal-provincial control agreements. A national emissions cap will be established for the year 2000 of 3.2 million tonnes of SO_2.[10]

4.3.2 Nitrogen Oxides

In 1988, the Canadian government signed a second protocol to the 1979 LRTAP Convention aimed at reducing NO_x emissions. Canada and the other signatories to the Protocol agreed to a freeze of NO_x emissions at the 1987 level, the use of best available technology economically achievable for new sources, and the establishment of further measures to solve NO_x-related environmental problems by 1996.

Under the auspices of this protocol, Canada's federal and provincial environment ministers initiated development of a management plan for the control of NO_x and VOCs, aimed mainly at solving existing ground level ozone problems. Based on a Canada-wide consultation program, a Draft Management Plan was released for public review in early 1990. Key areas for the management of NO_x/VOCs included: control technologies, energy efficiency, fuel switching (including new energy supply technologies), research and development, apportionment of NO_x/VOC emission reductions, and assessment of the impact of NO_x/VOC emissions on health, vegetation and animals. The Draft contains sixty-one initiatives for reduction of NO_x and VOC emissions and an additional twenty initiatives designed to provide further information for preparing a second draft in 1994. Implementation of the initiatives will be shared by federal, provincial and municipal jurisdictions.

The NO_x/VOC Draft Management Plan cites major implementation costs to government, industry and the general public. Direct measures taken to reduce NO_x emissions are estimated to cost $630 million per year by 2005.[11]

When fully implemented, the Draft is expected to result in:

- NO_x and VOC emissions nationally by 2005 that are 16 percent and 19 percent, respectively, below 1985 emission levels, with reductions of about 30 percent in key ozone problem areas.

- A reduction in peak ozone levels ranging from 15 to 35 percent in most areas of concern with respect to elevated summertime ozone concentrations.
- A reduction in emissions of CO_2 of approximately 6 percent from the level projected for 2005.[12]
- Consistency with Canada's international obligations under the NO_x Protocol (NO_x emissions under the plan would be about 5 percent below the 1987 level by December 31, 1994, the date specified for a freeze at the 1987 level).

Draft NO_x control measures identified for Canada's electric power sector are described below.

4.3.2.1 Energy Conservation and Efficiency Standards

The Draft recommends that utility demand-side management (DSM) programs be in place by 1993 and that energy efficiency standards for selected electrical equipment (appliances, motors and lighting) be in place by 1994, targeting a minimum reduction in NO_x emissions of 10 percent in 2000 and 15 percent in 2005.

Development of energy efficiency performance standards and DSM plans will be coordinated by the Federal Department of Energy, Mines and Resources in cooperation with provincial energy departments and utilities. The reduction in total NO_x emissions resulting from these measures is estimated as 38.8 kt in 2005.[13]

4.3.2.2 New Source Performance Standards (NSPS)

The Draft notes that most of the new coal-fired generating capacity between now and 2000 will be in Alberta, Saskatchewan and the Atlantic Provinces. Without implementing tighter controls, Environment Canada forecasts NO_x emissions from power generation will increase by over 40 percent, despite the assumption of no new fossil generating capacity in Ontario and Quebec. To limit this growth, the Draft suggests tighter NO_x controls on new power plants be implemented in a staged manner (see Table 4.7).

TABLE 4.7

NATIONAL EMISSION LEVELS
(ng of NO_2 per joule of heat input)

Fuel	Current	Effective 1995	Effective 2000
Coal	258	150	100
Oil	129	110	90
Gas	86	50	30

SOURCE: Federal/Provincial Long-Range Transport of Air Pollutants Steering Committee, *Management Plan for Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOCs), First Edition (Draft)* (Ottawa, Ontario: Environment Canada, March 1990), p. 92.

This initiative calls for an interim limit in 1995 to provide some flexibility and to account for long lead times for power station planning, approval and development. The Draft asserts that this staged reduction is reasonable, providing significantly reduced emissions from 1995 onward, and will stimulate more rapid development of higher efficiency, low emission combustion technologies such as integrated gasification combined cycle (IGCC). Total annual NO_x reductions are estimated to be 30 kt less in 2005 than would be the case otherwise.[14]

4.3.2.3 Region-Specific New Source Performance Standards

Owing to the severity of regional ozone episodes, the Draft recommends that new performance standards apply to all new power plants for the Lower Fraser Valley and Windsor-Quebec City corridor effective in 1995, and that existing fossil-fuelled power plants in those areas be retrofitted by 1997 to NO_x emission levels no less stringent than:

Coal	100 ng/J of heat input
Oil	90 ng/J of heat input
Gas	30 ng/J of heat input

The plan suggests that actual emission limits be determined by the Ontario and British Columbia governments by December 31, 1992 for both 1995 NSPS and 1997 existing plant retrofits.[15]

The total estimate of NO_x emissions reductions resulting from electric power control measures suggested in the Draft plan is depicted in Figure 4.11. Ontario, Alberta, New Brunswick and Saskatchewan together account for 94 percent of projected reductions. By 2005, total Canadian NO_x emissions are expected to fall over 320 kt from what they would have been without the tighter NO_x guidelines recommended in the Draft. Emissions from electricity production are projected to fall 127 kt from their estimated level without tighter emission controls--almost 10 percent below 1985 NO_x emissions.

Demand-side management, NSPS and region-specific NSPS account for 30, 24 and 46 percent, respectively, of total NO_x reductions from Canada's electric power sector.

4.3.3 Utility Initiatives on Acid Gas

As noted earlier, Canada's provincial governments and electric utilities are in the process of reviewing the recommended provincial allocation of NO_x emissions reductions and cost-effective programs capable of meeting the federal government's commitments under the NO_x Protocol. Implementation of programs to limit utility emissions seem likely in the near term, but it is uncertain what combination of programs (i.e., new technologies, DSM, non-utility generation, etc.) will be deemed most cost effective by electric utilities for the 1990s.

A set of agreements on provincial emissions for SO_2 has existed since the mid-1980s and several provinces now have specific regulations in place governing electric utility emissions of SO_2. Of the seven eastern provinces, Manitoba and Quebec are almost entirely independent of fossil-fuelled electrical generation; the provincial utilities in Ontario, New Brunswick and Nova Scotia are the heaviest users of coal and are thus faced with most of the SO_2 reduction burden (see Table 4.8).

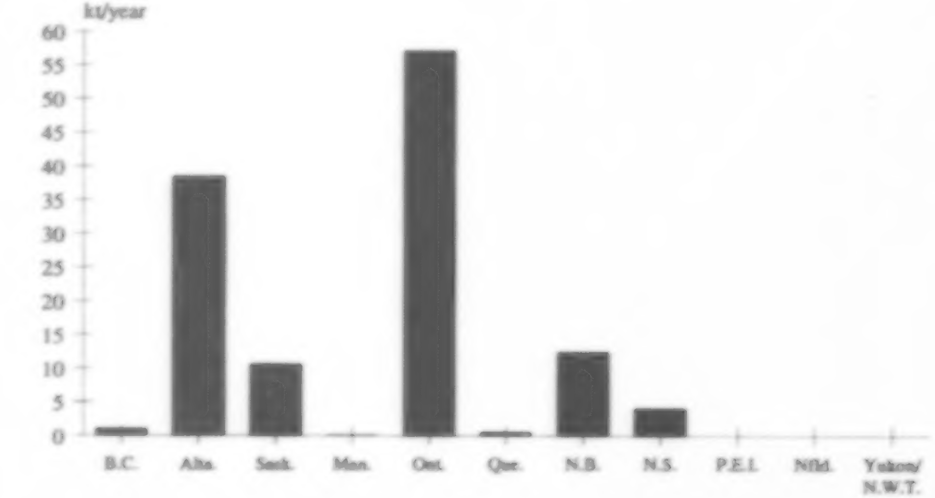
4.3.3.1 Ontario

The Province of Ontario has set regulations which require Ontario Hydro to reduce emissions of acid gas in stages. From 1986 to 1989, total emissions must not exceed 430 kt per year; from 1990 to 1993, emissions must not exceed 280 kt per year; and for 1994 and beyond, total acid gas emissions may not exceed 215 kt per year.

Figure 4.11

Provincial NO_x Emission Reductions

2005



SOURCE: Environment Canada Draft Management Plan, March 1990.

TABLE 4.8

UTILITY EMISSIONS TARGETS FOR ACID GAS UNDER THE CANADIAN ACID RAIN PROGRAM

Utility	Emissions Target
Ontario Hydro	• From 1986 to 1989, acid gas emissions must not exceed 430 000 tonnes, and of this total, no more than 370 000 tonnes may be sulphur dioxide.
	• From 1990 to 1993, acid gas emissions must not exceed 280 000 tonnes, and of this total, no more than 240 000 tonnes may be sulphur dioxide.
	• In 1994 and subsequent years, Ontario Hydro's acid gas emissions must not exceed 215 000 tonnes, of which no more than 175 000 tonnes may be sulphur dioxide.
Nova Scotia Power Corporation	• Emissions of sulphur dioxide must not exceed 160 000 tonnes per annum by the year 1994.
New Brunswick Power Commission	• Emissions of sulphur dioxide must not exceed 130 000 tonnes per annum by the year 1994.

SOURCES: (1) Ontario Hydro, *Options Available to Meet Acid Gas Limits and Selection of Preferred Options* (Toronto: Ontario Hydro, January 31, 1989); (2) Canadian Electrical Association, Generation and Research and Development Committee; and (3) Environment Canada, unpublished report.

Ontario Hydro plans to retrofit flue gas desulphurization (FGD) scrubbers at two 500-MW coal-fired units at Lambton generating station by 1994 and may need many more FGD retrofits, depending on the province's electrical load growth. For the long term, Ontario Hydro's plans to reduce acid gas emissions include load management and conservation, purchases from neighbouring utilities, nuclear program development and the evaluation of IGCC plants.[16]

4.3.3.2 New Brunswick Power

As its response to SO_2 control, New Brunswick Power has developed an emission strategy whereby total annual emissions of SO_2 from thermal power plants will be limited to 130 kt.

New Brunswick Power's development plan is largely coal-based, with a major 450-MW coal-fired plant planned at Belldune for 1994. This plant will be built with FGD equipment. As well, other plants will either be converted to burn low-sulphur coals or be retrofitted with FGD scrubbers. New Brunswick Power is also seriously investigating the use of IGCC for future additions to its electrical generating capacity.

4.3.3.3 Nova Scotia Power Corporation (NSPC)

Nova Scotia Power Corporation has set a limit for SO_2 emissions in 1994 of 160 kt. In 1980, NSPC emitted 122 kt of SO_2 from fossil-fuelled stations. By the year 2000, projections are for emissions of about 100 kt, despite a forecast increase in fossil-fuelled electricity generation of over 80 percent in the 1980-2000 period. This dramatic fall in SO_2 emissions will result from burning low-sulphur coal and the installation of FGD scrubbers.[17]

Sulphur dioxide reductions are now being achieved by burning low-sulphur coal. Future reductions will take place as the utility installs fluidized bed combustion (FBC) units to supply increasing demands for electrical power beyond the turn of the century. Canada's first 150-megawatt FBC unit has been ordered for the mid-1990s at Point Aconi, Nova Scotia and will permit NSPC over 90 percent sulphur capture. Nova Scotia Power Corporation is also conducting research on retrofitting options such as limestone injection and new technologies such as IGCC in order to address emissions from existing thermal units.

Other eastern Canadian utilities rely, at least in part, on heavy oil generation. Sulphur dioxide reductions at these plants will generally be achieved by switching to low-sulphur fuels.

4.3.4 Canada/United States Bilateral Agreements on Acid Rain

Some of Canada's most populous regions and most acid-sensitive environments are located downwind from major urban and industrial centres in the United States. As a result, a significant component of the NO_x, VOCs and SO_2 pollutants that occur in Canada originate in the United States. This is well known in the Windsor-Quebec City corridor but is also true of Halifax, where high pollutant episodes have been linked to air flows from major urban areas on the U.S. eastern seaboard.

For a decade, Canada has been pressing the United States to implement a comprehensive acid rain control program. As reported in the Green Plan, these efforts have been rewarded through U.S. Congress legislation providing for a ten-million-ton reduction in U.S. SO_2 emissions and a permanent cap at the reduced level. By the year 2000, it is expected that this program will reduce the trans-boundary flow of acid rain into eastern Canada by more than 50 percent.

4.3.5 Carbon Dioxide

As a result of increasing concern over the buildup of man-made greenhouse gases, Canada's federal, provincial and territorial governments have taken a number of initiatives to evaluate the possible consequences of global warming and cost-effective options to reduce CO_2 emissions.

In June 1988, Canada hosted a major international conference on global climate patterns which recommended that world-wide emissions of greenhouse gases be reduced by 20 percent from 1988 levels, by the year 2005.

4.3.5.1 Task Force on Energy and the Environment

Following the heralded "20 percent" reduction target recommended at the 1988 conference, federal, provincial and territorial energy ministers established a task force to review energy-related measures to reduce CO_2 emissions in Canada. In August 1989, the Task Force reported that due to the **global** nature of the problem, the

scientific uncertainties related to global warming and the need for **regional** assessments of ways to reduce emissions, the recommendation of a "20 percent" reduction should be considered an **illustrative target**, not a formally adopted goal.

The Task Force presented a second report in April 1990, concluding that: (1) the potential for CO_2 reductions varies considerably across the country; (2) the achievement of a 20 percent reduction by 2005 levels is **not practical** and would cause significant economic dislocation; and (3) a prudent course of action would be to take steps towards the stabilization and eventual reduction of carbon dioxide levels, given the potential impacts of global warming.

In the spring of 1990, the federal government took the position that it would work towards the stabilization of CO_2 emissions by the year 2000 at 1990 levels and that the place to resolve the question of targets is in the context of international negotiations.

4.3.5.2 The Green Plan

Canada's Green Plan strategy was formally released in early December, 1990. The Plan commits the Government of Canada to $3 billion over five years in new funding for the environment and sets out more than 100 initiatives. The Global Environmental Security component allocates $575 million to stabilize emissions. Some of the initiatives allocated to these funds include:

- introduce a National Energy Efficiency and Alternative Energy Act providing authority to regulate minimum energy efficiency levels in equipment, to provide energy use information on product labels, and to collect national energy use information;
- increase support for development and commercialization of promising energy-efficient technologies such as better windows, lighting, heating and cooling systems;
- accelerate development and market penetration of alternative transportation fuels through such efforts as increased availability of alternative fuel vehicles, promotion of ethanol and methanol as automotive fuels and fuel feedstocks, and expansion of natural gas markets;
- increase support for research and development of alternative energy sources, including photovoltaics, fuel cells, landfill gas recovery and passive solar energy; conduct cost-shared market assessments of

non-fossil fuel energy sources; and increase research, development and demonstration of advanced energy systems;

- release in 1991 a discussion paper on the use of economic instruments to achieve environmental objectives, including an analysis of taxes and an emissions trading system to attain reductions in greenhouse gas emissions;

- establish an inquiry into the environmental impacts of options for electricity generation;

- pursue aggressively an International Framework Convention on Climate Change with appropriate binding protocols by 1992 for the world-wide reduction of greenhouse gas emissions, enhanced cooperation on climate change science, assistance to developing nations, and cooperation in the development and commercialization of new technologies.

Footnotes

[1] Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls (Draft)* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-15.

[2] VOC emissions from electric power plants in 1985 were 1928 kt compared to a total of 486 032 kt or 0.4 percent and are not, therefore, considered further in this report (see Canada, Federal/Provincial Long-Range Transport of Air Pollutants Steering Committee, *Management Plan for Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOCs) First Edition - (Draft)* (Ottawa, Ontario: Environment Canada, March 1990).

[3] Emission of nitrogen oxides are primarily associated with the combustion of fossil fuels. Transportation represented the largest contribution of NO_x emissions on a national basis--64 percent of total emissions by anthropogenic sources.

[4] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-14.

[5] Ibid., p. 2-23.

[6] Ibid., p. 2-73.

[7] Environment Canada, *Fact Sheet - The Impacts of Global Warming* (Downsview, Ontario: Supply and Services Canada, 1986) p. 2.

[8] Electric Power Research Institute. "The Politics of Climate." *EPRI Journal* (June 1988): p. 7. See also, Hatch Associates Ltd, *CO_2 Emissions: Perspectives and Future Options for Canadian Electric Utilities and the Coal Industry,* Vol. II (Toronto, Ontario: Hatch Associates Ltd., January 1990), pp. 60-1.

[9] See Federal/Provincial/Territorial Task Force on Energy and the Environment, *Report on Reducing Greenhouse Gas Emissions* (Ottawa, Ontario: August 1989).

[10] Government of Canada, *Canada's Green Plan* (Ottawa, Ontario: Minister of Supply and Services Canada, 1990), pp. 119-120.

[11] Environment Canada, *Emissions and Controls (Draft)* February 1990, pp. xii-xx. See also Government of Canada, *Canada's Green Plan*, 1990, pp. 51-56.

[12] Ibid., p. xii.

[13] Ibid., pp. 82-84.

[14] Ibid., pp. 91-92.

[15] Ibid., pp. 99-100.

[16] Environment Canada, *Emissions and Controls (Draft)* February 1990, pp. 2-34 and 2-35.

[17] Ibid., p. 2-37.

Chapter 5

EMISSION CONTROLS, ADVANCED GENERATION TECHNOLOGIES, FUEL CELLS AND MAGNETOHYDRODYNAMICS

5.1 Introduction

Over the last decade, technologies for the control of emissions from coal have progressed considerably with improvements in coal-cleaning processes, advances in fuel combustion, and in the cleaning of exhaust gases after combustion. The term clean coal technologies is commonly used to refer to this set of new systems and processes that produce fewer air pollutants than conventional combustion methods. As carbon dioxide (CO_2) has only recently become of interest, technological developments have largely focussed on control of particulates, sulphur dioxide (SO_2) and nitrogen oxide (NO_x) (see Appendix A for a detailed presentation of emission control technologies).

Control of pollutants released in the combustion of coal can be achieved in several ways:[1]

- Capture of particulate emissions after combustion by electrostatic precipitators and bag filter systems.
- Reduction of sulphur dioxide emissions prior to combustion by switching to low-sulphur fuels or by removing sulphur from the coal (e.g., by coal washing or coal gasification); during combustion; or after combustion by treating the flue gas.
- Reduction of nitrogen oxide emissions by combustion modification techniques or, following combustion, by flue gas treatment devices.

In addition to particulates, SO_2 and NO_x, solid and liquid by-products or wastes are also formed during combustion and in the control of emissions. For example, waste produced in the desulphurization of flue gases is now regulated, particularly where adequate space for waste disposal is problematic. In many cases, regulations to control waste by-products will limit control technology options and ultimately influence the costs of emissions control. Table 5.1 summarizes the control technologies for SO_2 and NO_x, including their commercial status and SO_2/NO_x reduction effectiveness.

Other techniques for reducing the sulphur content of coal used in the generation of electricity include coal switching, coal gasification, coal liquefaction and coal-oil co-processing. Switching to low-sulphur coal may be cost effective in some situations; however, there are technological constraints to using low-sulphur coal in utility boilers originally designed to burn coal of a higher sulphur content. Upgrading of particulate control devices may be required and coal handling equipment may also require upgrading to compensate for the greater quantities of lower heat content coal required to generate an equivalent amount of electricity. These factors add to the cost of generating electricity and may lead to derating of the boiler.[2]

Other pre-combustion treatments, such as the conversion of coal to gas or liquid fuels, offer the possibility of using coal more cleanly. For example, the development of gasification processes to produce synthetic gas for the combined cycle generation of electricity (IGCC) looks extremely promising and considerable demonstration activity is underway world-wide. Coal liquefaction and coal-oil co-processing remain longer-term options which result in cleaner use of coal. As transportation fuels are the main products of these processes, they are not considered in this report.[3]

5.2 Control of SO_2 Emissions

The choice of a flue gas desulphurization (FGD) system depends on a variety of factors including cost, operating characteristics, ability to handle different qualities of coal, performance and waste by-products. The types of FGD systems currently in operation are described in Table 5.2. Also shown are the variety of sorbents and end-products produced by each system.

Of the many types of FGD technologies, wet limestone scrubbers producing sludge waste were first generation systems. Initial refinements to FGD technology added an oxidation process which facilitates the production of gypsum, a by-product used in construction. Dry, semi-dry and regenerable processes represent yet another generation of FGD technologies.

One means of reducing solid waste disposal is to use FGD systems that produce a saleable by-product. For example, several utilities are currently relying on forced-oxidation FGD which injects

TABLE 5.1

POWER PLANT CONTROL TECHNOLOGY FOR SULPHUR AND NITROGEN OXIDES

Technology	Commercial Status	Application/Waste	SO_2 and NO_x Reduction[a]
Pre-Combustion			
Physical Coal Cleaning	Commercial		10-30% SO_2[b]
Advanced Coal Cleaning	R&D		90% SO_2[b]
Coal-Water Fuels	R&D, Small Industrial Scale		50% pyritic SO_2 and some NO_x
Combustion Control			
Combustion Modification/ Low-NO_x Burners	Commercial as well as R&D	Retrofit and New	30-50% NO_x
Advanced Low-NO_x Burners	R&D		Up to 70% NO_x
Off-Stoichiometric Control	Commercial	New	30% NO_x
Catalytic Combustion	Initial Testing	Retrofit	80% NO_x
Furnace Sorbent Injection	Demonstration	Retrofit: Waste May be Hazardous	60-75% SO_2
Post-Combustion			
FGD-Wet Lime and Limestone	Commercial	New and Retrofit; Gypsum or Wet By-product	90% or more SO_2
Spray-dryer FGD Lime	Commercial	New and Retrofit; Dry By-product	70-80% SO_2
Regenerable FGD	Commercial	New; Limited Quantities of Waste	90% SO_2
Combined de-SO_2/de-NO_x FGD	Demonstration	Small Quantities of Waste; New and Retrofit	90% SO_2/80% NO_x
Selective Catalytic Reduction	Commercial	Industrial and Utility; New and Retrofit	80-90% NO_x
Selective Non-Catalytic Reduction	Commercial	Compact and Easy to Install; Waste May be Considered Hazardous	30-50% NO_x
Dry Injection of Sorbents	R&D and Demonstrated		N.A.

SOURCE: International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1989), p. 59.

[a] Values indicated here are only indicative. Technologies are under development and experience with demonstration plants may differ and may also vary with coal qualities. For example, Denmark's experience with FGD technology suggests that wet lime and limestone SO_2 reductions of 93 percent can be attained, while for Selective Non-Catalytic Reduction, NO_x reductions of not more than 60 percent are expected.

[b] Depending on differences between pyritic and organic sulphur content across various types of coals.

TABLE 5.2

TYPES OF FGD SYSTEMS CURRENTLY IN OPERATION

System	Sorbent	End Product
Non-regenerable Systems		
Wet Scrubbers	Lime/Limestone Lime/Fly Ash	Gypsum or Calcium Sulphite/Sulphate Calcium Sulphite/Sulphate/Fly Ash
Spray-Dry Scrubbing	Lime	Calcium Sulphite/Sulphate/Fly Ash
Seawater	Primary: Seawater Secondary: Lime	Waste Seawater
Walther	Ammonia	Ammonium Sulphate
Regenerable Systems		
Dual Alkali	Primary: Sodium Hydroxide Secondary: Lime/Limestone	Calcium Sulphite/Sulphate
Bergbau-Forschung/Uhde	Activated Carbon	Concentrated SO_2
Wellman-Lord	Sodium Sulphite	Concentrated SO_2
Linde-SOLINOX	Physical Absorption	Concentrated SO_2
Spray Dry Scrubbing	Sodium Carbonate	Elemental Sulphur
MgO-Process	Magnesium Oxide	Concentrated SO_2
Electron Beam	Lime Ammonia	Ammonium Sulphate and Ammonium Nitrate

SOURCE: International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1989), p. 62.

compressed air into the scrubbing products and creates gypsum. Gypsum disposal is generally easier and less costly than typical FGD waste (requiring 40 percent less acreage for disposal because of ease to dewater) and with upgrading can result in a commercially saleable product for the cement and wallboard industries.[4]

Ontario Hydro is considering both spray dry and dual alkali scrubbers for new units and limestone slurry scrubbers for the retrofit of some existing units. Flue gas desulphurization is to be fitted to a new plant currently under construction in New Brunswick. These will be the first SO_2 scrubbers in coal-fired power plants in Canada.[5]

5.3 Control of NO_x Emissions

Nitrogen oxides are formed during combustion by the combination at high temperatures of nitrogen and oxygen naturally found in the air and from fuel-bound nitrogen. In the case of coal and residual oil, most of the NO_x is derived from fuel nitrogen.[6] As NO_x production is dependent on combustion regimes, the range of NO_x emissions for a specific fuel is wide and difficult to characterize. For example, the level of NO_x emissions from the same fuel varies considerably by type of plant (e.g., cyclone, wall-fired units or tangential-fired boiler). In addition, design characteristics such as spacing of burners and fuel mixing also affect the rate of NO_x emissions.

The two main approaches to NO_x reduction are modification of the combustion process (by modifying the flame or adding a secondary combustion zone) and reaction of the NO_x with ammonia. The reaction may take place by injecting ammonia into the ductwork, called selective non-catalytic reduction (SNCR), or in special plants after the boiler containing a catalyst to aid the reaction, termed selective catalytic reduction (SCR).

5.3.1 Selective Catalytic Reduction

Although SCR can achieve very high NO_x reductions, it has a number of disadvantages relative to the other NO_x control systems. These include high installation costs in a new coal-fired boiler (see Table 5.3) and relatively high operating and maintenance costs due to the need for periodic catalyst replacement, usually every two years. High-sulphur coal use in conjuction with SCR technology can create additional problems. The same catalysts that promote destruction of NO_x molecules also encourage oxidation of SO_2 and SO_3. In turn,

TABLE 5.3

SUMMARY OF NO_x CONTROL TECHNOLOGIES FOR COAL-FIRED BOILERS

Technology	Status/Size/ Applicability[a]	NO_x Reduction[b] (%)	NO_x Level Achievable[c] (ng/Joule)	NO_x Reduction Costs[d] ($1988/tonne)
Combustion Modification				
Low Excess Air	D, A	5-25	190	56[e]
Low NO_x Burners	D, A	20-50	130	45-90
Over Fire Air	D, AS	20-40	150	>30
Air Staging	D, AS	50-80	60-130	N/A[f]
Flue Gas Recir.	D, A	20-50	--	200
Fuel Reburning	D, AS	>60	<130	>300
Slagging Combustors	P, AL	>70	60-250	N/A
Advanced Sorbent Injection	D, AS	<90	>85	630-900
Selective Catalytic Reduction	D, A	90	26	2000-4000[g]
Copper Oxide Reduction	R, AS	90	26	N/A
NOXSO Process	R, AS	90	26	N/A
SULF-X Process	R, AS	80	50	N/A
Electron Beam	R, A	>80	50	N/A

SOURCE: Environment Canada, *Control Technologies for Management of NO_x and VOCs in Canada*, Work Sub-Group 6.2 Report (Ottawa, Ontario: Environment Canada, January 1990, p. 6).

[a] The codes are: Status

D: Demonstrated - Fully available with little additional work needed.
P: Pilot scale/needs demonstration or scaling up.
R: Needs development and demonstration.

Applicability

A: Applicable to new and most existing units.
AS: Applicable to new and some existing units.
AN: Applicable to new units only.
AL: Application limited to a class of units.

[b] Note that percent reductions are shown to provide an order to magnitude impression of achievable reductions. Actual reduction will vary depending on the current emissions levels and technical characteristics of each installation. The base levels used was 258 ng/Joule for coal-fired units.

[c] What is achievable will vary somewhat from installation to installation even for similar units; the values are given as typical values only.

[d] Cost figures are approximate only and exclude additional expenses which may be incurred in specific installations such as modifications to boiler pressure parts, major changes to boiler controls, siting costs, etc.

[e] These costs are usually largely offset by energy efficiency improvements.

[f] N/A indicates that cost figures are not available; a dash indicates that an entry is unavailable or that costs are too imprecise to be included.

[g] Personal communication with Environment Canada.

these compounds combine with slip ammonia to form solid and liquid sulphates which can be deposited in the air preheater where they interfere with heat transfer, cause corrosion, and plug passages.

Contamination of ash with ammonia by-products is also possible which may increase waste disposal costs or create an inferior ash by-product. These problems are less pronounced with the low- and medium-sulphur coals typical of Japanese and German applications. More research on these and other issues related to coal quality and differences between foreign and domestic operating practices is needed before SCR technology is commercially established for Canadian utility applications.[7]

5.3.2 Selective Non-Catalytic Reduction

Another post-combustion NO_x removal technique recently commercialized is SNCR or advanced sorbent injection, where NO_x removal takes place at higher temperatures and without a catalyst.

Advanced sorbent injection for NO_x removal involves the addition of reactants, such as urea, in solution to the cooler upper-furnace area. Proprietary enhancer chemicals control the formation of ammonia, which is a by-product of the reaction of urea and NO_x, and control the reaction conditions. When combined with the injection of a calcium-containing sorbent (e.g., limestone, hydrated lime or dolomite) in a dry or slurry form, the process can remove substantial quantities of both SO_2 and NO_x. These systems are considered demonstrated in commercial scale applications in the United States, Germany and Japan. In Canada, a limestone and urea slurry has undergone pilot-scale testing in Ontario. In demonstration results, the process is claimed to be capable of up to 90 percent NO_x reduction and 85 percent SO_2 reduction. In a large boiler, the NO_x removal cost is estimated to be about half that of SCR per tonne of NO_x reduction.

A major advantage of SNCR compared to SCR is that catalysts are not required, which lowers operating costs and reduces space requirements. However, SNCR has several potential problems. The process can release ammonia; it also produces ammonia sulphate as a by-product, which can disrupt the system and corrode the boiler; and there are problems with proper construction of the units. While the technology has been applied successfully in gas- and oil-fired utility boilers in Japan, the application of SNCR to large-scale coal-fired units in North America has not been demonstrated. It appears that SNCR may be most economic for small industrial furnace applications.[8]

5.4 Combined SO_2 and NO_x Control

Several innovative clean coal technologies are currently under development that simultaneously achieve moderate to high removal rates for both sulphur dioxide and nitrogen oxides. These technologies include limestone injection multi-stage burners (LIMB), advanced slagging combustors, gas reburning coupled with in-duct sorbent injection (GR-SI), electron beam (E-beam), copper oxide, NOXSO and SULF-X.

Many of these systems regenerate the sorbent and recover sulphur or sulphuric acid from the flue gas and many are also suitable for retrofit. Demonstrations have shown SO_2 removal of 90 percent or more and NO_x removal up to 80 percent. A fundamental advantage of such systems is a combined lower average cost compared to those for separate control systems with comparable levels of SO_2 and NO_x reductions. Furthermore, they may be designed to use less energy than conventional FGD and, unlike FGD, do not produce large quantities of waste.[9]

5.4.1 Advanced Systems for NO_x and SO_2 Control

Several advanced flue gas systems are also under development. Each of these systems has the potential to reduce both SO_2 and NO_x by 90 percent. Moreover, they have the capability to regenerate the sorbent or produce a by-product (e.g., fertilizer). Unlike flue gas scrubbers, these processes do not produce large quantities of by-product waste. Two systems are currently classified as advanced flue gas clean-up technologies--E-beam and copper oxide reduction.

5.5 By-Product and Wastes

Most of the technologies for the control of air pollution generate solid waste by-products. Efforts to increase the efficiency of emissions reduction is leading to higher costs and greater waste volumes. As the volume of solid wastes increases, disposal may become increasingly difficult and alter the balance between competing pollution control technologies in favour of those that produce useable by-products.[10]

In some countries, the disposal of wastes from FGD and sorbent injection is already a key issue. For example, in Japan and Germany, legislation prohibits dumping when re-use of wastes is possible. As a result, systems producing gypsum, which can be sold to the building industry, have been preferred. However, some objections to gypsum production are now being raised due to limited market size compared with the large quantities produced by power plants, and the large volume of limestone reagent required. Recently, concern has also arisen over the possible hazardousness of the wastes.[11]

As a result of growing regional concern over waste management, regenerable FGD processes are the object of increasing research and development. However, as regenerable systems tend to be more complex, less well-developed, and more costly, most FGD installed today continues to be of the wet lime/limestone process producing either gypsum residue or saleable gypsum.[12]

5.6 The Canadian Setting

Proven technologies available to reduce SO_2 emissions from smelters, power plants and other sources have been applied or are expected to be implemented within a few years. By 1994, state-of-the-art technologies will be in place in Canadian non-ferrous smelters. Flue gas desulphurization scrubbers (wet limestone type) are planned at several electric power plants. In Ontario, between two and twelve coal-fired units will be retrofitted depending on load growth. In New Brunswick, new coal-fired units with scrubbers are planned and one is now under construction at Belledune. For these scrubbers, commercial gypsum recovery is being investigated.

While these control technologies will play a significant role, particularly for existing plants, they impose an energy penalty and pose other environmental problems, such as sludge disposal and water contamination. New control technologies which permit simultaneous treatment of SO_2 and NO_x, such as the copper oxide process, may replace conventional scrubbers if current research and development (R&D) programs prove to be successful. However, in the long run, new, more energy-efficient production technologies will replace the conventional plants.[13]

Major advances in NO_x control technologies are in use in Japan, Germany and California. However, some of the most promising technologies require further research, development and demonstration for Canadian fuels under Canadian conditions.[14,15]

Of the various options for controlling emissions (pre-combustion, combustion and post-combustion), combustion technologies present the greatest opportunities for increases in thermal efficiency and net reductions in CO_2 and other radiative gas emissions.[16] Owing to the fact that coal-fired electrical plants are in the order of 35 percent energy efficient, every percentage improvement in efficiency has a leveraged impact on the reduction of emissions. Many of these advanced generation technologies also result in significantly improved methods of controlling SO_2 and NO_x emissions.

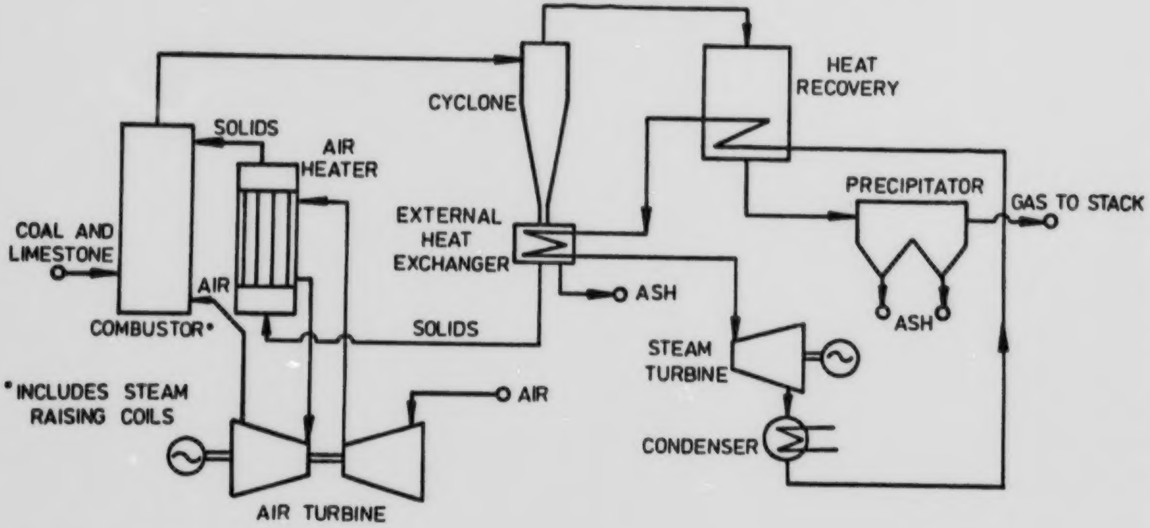
5.7 Advanced Generation Technologies

World-wide research by the electric power, chemical and coal industries has led to the development of a range of combustion technologies which mitigate the environmental impacts of burning coal for electric power generation--atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC) and IGCC (see Figures 5.1, 5.2 and 5.3, and Appendix B for a detailed presentation of these technologies).

Of these new technologies, IGCC promises the best combination of economic, efficiency and environmental benefits. It has been identified by many electric utilities as the coal-based power generation technology for the 1990s. Almost all the sulphur (99 percent) can be removed and produced in a saleable molten form and NO_x emissions are extremely low at around 25 percent of conventional coal-fired plants. Application of low NO_x burners, under development for gas turbines, will lower NO_x emissions further.

In assessing the relative merits of a new technology, it is important that the environmental performance, capital cost, lead time to design, install and commission the plant, the overall energy efficiency of the plant, and the status of development and technological risk be assessed. When evaluated against these criteria, IGCC offers a combination of advantages which no other coal-based system can match. Integrated gasification combined cycle provides short lead time construction, competitive capital cost, operational and planning flexibility, lower water consumption, small land requirements, and markedly reduced sulphur, nitrogen, particulate and CO_2 emissions relative to conventional coal-fired power plants. Ongoing progress in gas turbine technology signals further gains in IGCC efficiency.[17] System improvements stemming from IGCC demonstration projects currently being built, together with that resulting from current pilot-scale research, portend additional gains in efficiency, lower costs and

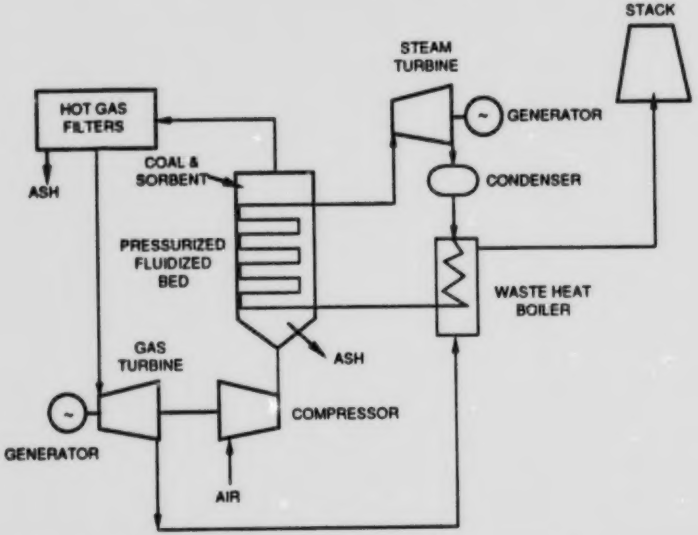
Figure 5.1
Atmospheric Circulating Bed Cycle



HEAT
RECOVERY
CYCLONE
SOLIDS
AIR
HEATER
PRECIPITATOR
GAS TO STACK
EXTERNAL
HEAT
EXCHANGER
COAL AND
LIMESTONE
AIR
ASH
ASH
COMBUSTOR*
SOLIDS
STEAM
TURBINE
*INCLUDES STEAM
RAISING COILS
AIR
CONDENSER
AIR TURBINE

SOURCE: A.D. Dainton, J.S. Harrison, and J. Holmes, "Advanced Cycles for Coal-Fired Power Generation," *8th International Conference on Coal Research*, Tokyo, Japan, October 16-20, 1988.

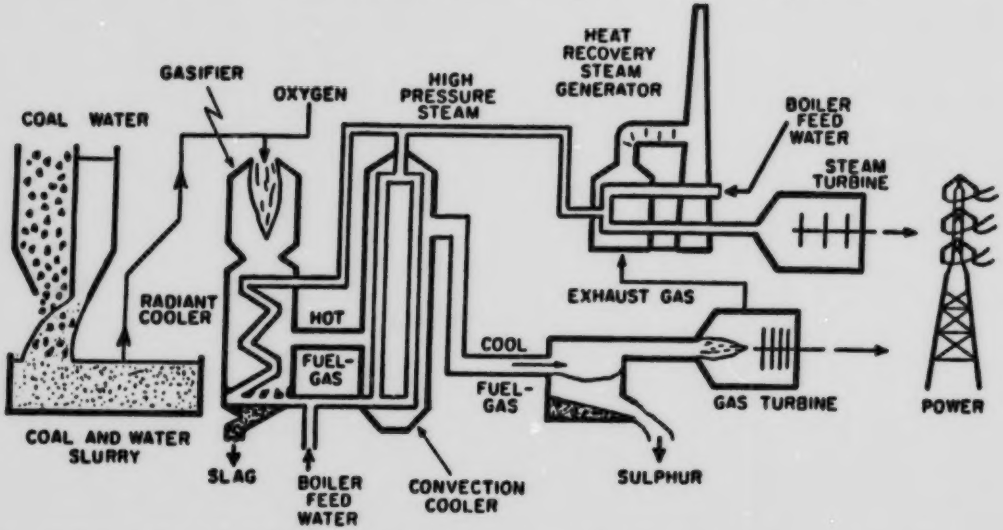
Figure 5.2
PFBC Combined Cycle Plant


STACK
STEAM TURBINE
HOT GAS FILTERS
GENERATOR
COAL & SORBENT
CONDENSER
ASH
PRESSURIZED FLUIDIZED BED
WASTE HEAT BOILER
GAS TURBINE
ASH
COMPRESSOR
GENERATOR
AIR

SOURCE: K.V. Thombimuthu, Environmental Benefits of Coal Liquid Fuels, Ottawa, Ontario: CANMET, 1989, p. 22.

Figure 5.3

Integrated Coal Gasification Combined Cycle System


COAL
WATER
GASIFIER
OXYGEN
HIGH PRESSURE STEAM
HEAT RECOVERY STEAM GENERATOR
BOILER FEED WATER
STEAM TURBINE
RADIANT COOLER
HOT
FUEL-GAS
EXHAUST GAS
COOL
FUEL-GAS
GAS TURBINE
POWER
COAL AND WATER SLURRY
SLAG
BOILER FEED WATER
CONVECTION COOLER
SULPHUR

SOURCE: G.K. Lee, Canadian Coals, "The Environment and New Coal Technologies," Presentation to the Canadian Energy Research Institute's *Energy and Electricity: A Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990.

major reductions in CO_2 emissions.[18] Moreover, IGCC affords a unique opportunity for co-producing valuable chemical by-products (see Figure 5.4).

As a result of these benefits, interest in IGCC utility applications is growing world-wide. In California, Texaco plans to have a commercial plant producing electricity from a mixture of 75 percent coal and 25 percent sewage sludge from Los Angeles by 1992. Materials such as contaminated soils, waste oils, and refinery wastes can also be combusted due to the higher temperatures at which gasifiers operate. The first commercial IGCC unit to come on-line in Europe is a 250-MW plant scheduled for completion in 1993 at Buggenum, Holland. Germany is planning to have a 150-MW IGCC unit in commercial operation by 1994.

In Canada, IGCC is under active investigation in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta. The Coal Association of Canada (CAC) has proposed a unique IGCC demonstration project which would evaluate CO_2 removal and disposal options such as enhanced oil recovery.

5.8 Fuel Cells and Magnetohydrodynamics (MHD)

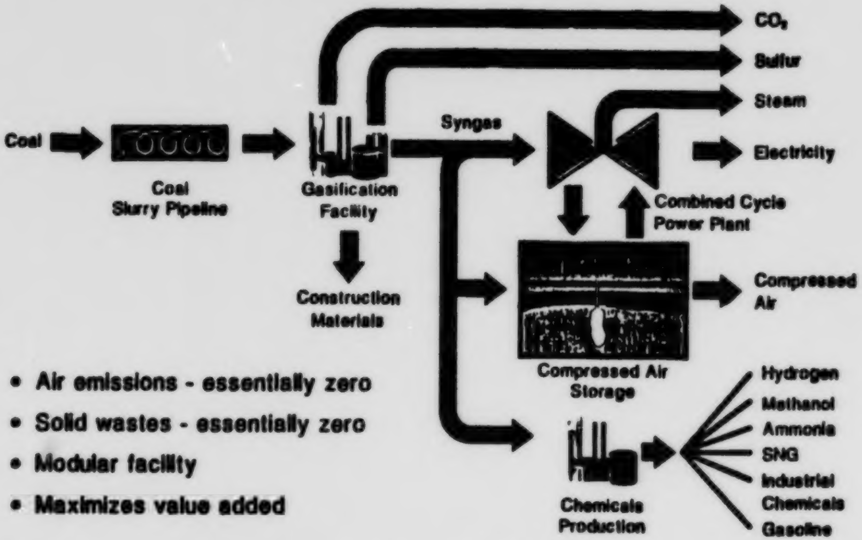
Two technologies under development which offer considerable promise are fuel cells and magnetohydrodynamics.

5.8.1 Fuel Cells

A fuel cell is a device in which hydrogen obtained by reforming natural gas, methanol, or coal-derived gas reacts electrochemically with oxygen to generate electric power (see Figure 5.5 and 5.6). The power generation efficiency of a fuel cell is high, some 40 to 60 percent, and these efficiency levels are maintained even under partial load operation. Waste heat recovery from fuel cell operations may yield total energy efficiencies of up to 85 percent where waste heat is used for domestic hot water, space heating, or low-level process heat for industrial uses.[19] Owing to their energy efficiency relative to conventional generating units, fuel cells offer a significant reduction in CO_2 emissions.

Since fuel cells have no combustion cycle, emissions of SO_x and NO_x, as well as the amount of cooling water discharged, are very small. Together with the absence of moving parts, their small size,

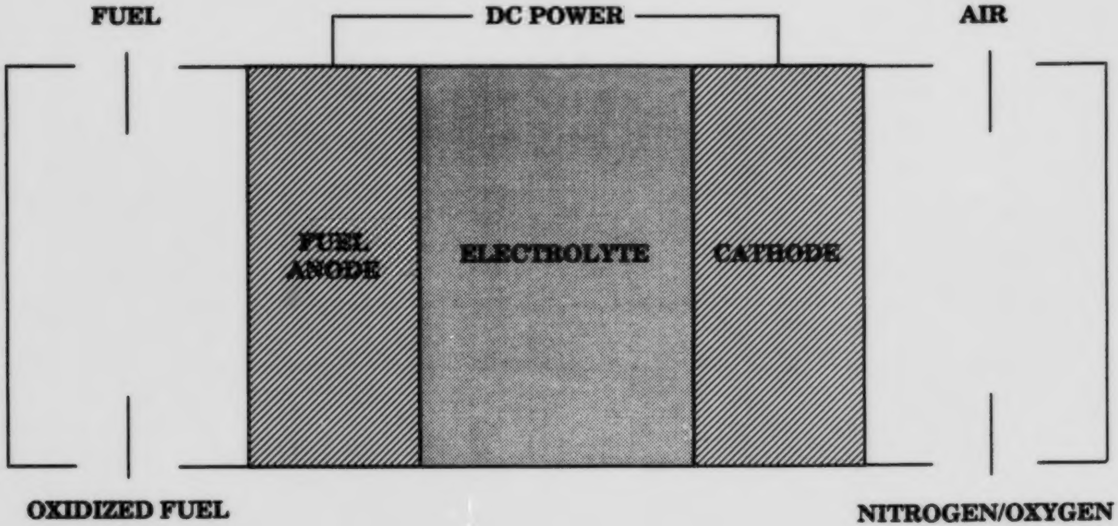
Figure 5.4
Integrated Energy Facilities


Coal
Coal Slurry Pipeline
Gasification Facility
Construction Materials
Syngas
CO₂
Sulfur
Steam
Electricity
Combined Cycle Power Plant
Compressed Air
Compressed Air Storage
Chemicals Production
Hydrogen
Methanol
Ammonia
SNG
Industrial Chemicals
Gasoline

- Air emissions - essentially zero
- Solid wastes - essentially zero
- Modular facility
- Maximizes value added

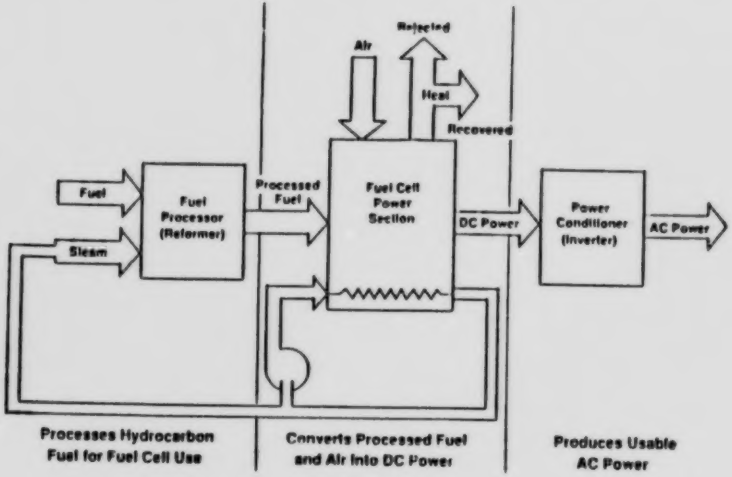
SOURCE: Michael Gluckman, "Status and Outlook for IGCC," Canadian Electrical Association, Canadian Perspectives for IGCC, Montreal, Quebec, March 29-30, 1990.

Figure 5.5
Fuel Cell


FUEL
DC POWER
AIR
FUEL ANODE
ELECTROLYTE
CATHODE
OXIDIZED FUEL
NITROGEN/OXYGEN

SOURCE: Hatch Associates Ltd., *CO_2 Emissions: Perspectives and Future Options for Canadian Electric Utilities and the Coal Industry*, Figure A8-4, January 1990.

Figure 5.6
Fuel Cell Power Plant


Air
Rejected
Heat
Recovered
Fuel
Steam
Fuel Processor (Reformer)
Processed Fuel
Fuel Cell Power Section
DC Power
Power Conditioner (Inverter)
AC Power
Processes Hydrocarbon Fuel for Fuel Cell Use
Converts Processed Fuel and Air into DC Power
Produces Usable AC Power

SOURCE: Manfield J. Mayfield, "Update on U.S. Department of Energy's Phosphoric Acid Fuel Cell Program," *Energy Technology XVI*, 1989, p. 194.

efficiency, and environmental attributes are expected to make fuel cells a very promising option in terms of environmental impact and siting.

Most fuel cell power plants comprise three main subsystems: a fuel processing unit (which extracts hydrogen from the fuel), the fuel cell stack power section and a power conditioner. The electrical power which flows from the fuel cell stacks is direct current (DC). A power conditioner is required to transform the direct current into alternating current (AC). This allows it to be fed into the electrical grid and to be used by AC electrical motors. In addition, an energy recovery system is usually provided to recover heat for process heating and gas compression requirements, thereby improving overall efficiency. In large systems, extra electric power may also be economically produced by adding a bottoming cycle, where waste heat is recovered and used to generate steam for a conventional steam-turbine generator (see Figure 5.7).[20]

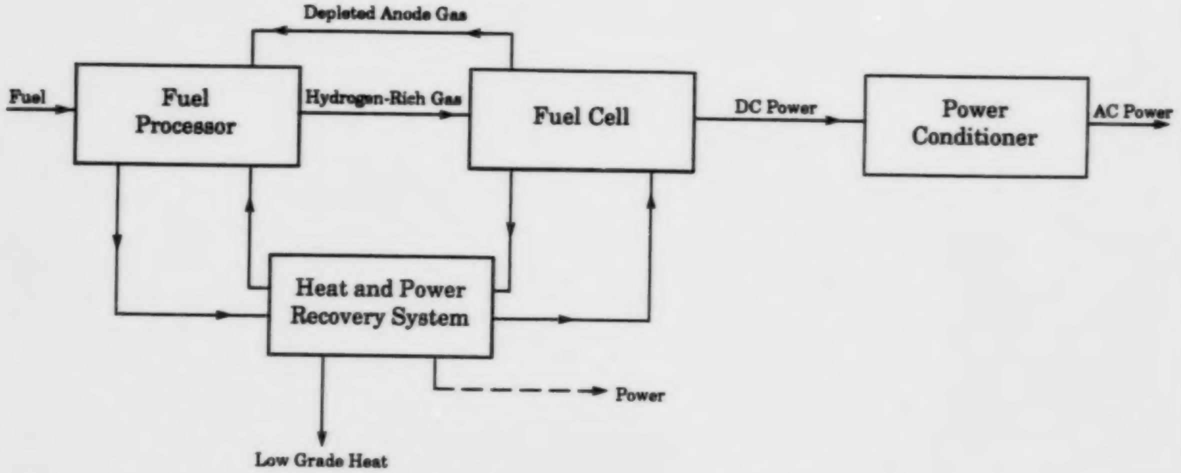
There are several types of fuel cells under development, categorized according to the type of electrolyte (or medium) in which the electrochemical reaction occurs. First-generation fuel cells use phosphoric acid as the electrolyte. Other, less mature fuel cell designs which employ alternative electrolytes promise superior performance. Of these, molten carbonate cells are the closest to commercial application.[21]

Fuel cells in capacities suitable for electric power plant use are unlikely to have been demonstrated in long-term operation much before the end of the century. The first commercial use is expected to occur in decentralized power generation and in load levelling applications, where their insensitivity to economies of scale and their relatively constant efficiency under varying loads make them extremely advantageous supply options.

While fuel cells are currently uneconomic, owing to their high capital cost, this situation will improve through continued R&D and eventual mass production. Financial credits stemming from their modularity, relative independence of efficiency on size and load, dispersibility and rapid installation time also reduce the effective capital costs.

Fuel cells appear to be one of the most promising systems for power generation in the 21st century because of their high efficiency, environmental compatibility and fuel diversity. As these features are exhibited regardless of unit capacity, it is expected that fuel cells will

Figure 5.7
Combined Cycle Fuel Cell Power Plant


Depleted Anode Gas
Fuel
Fuel Processor
Hydrogen-Rich Gas
Fuel Cell
DC Power
Power Conditioner
AC Power
Heat and Power Recovery System
Power
Low Grade Heat

SOURCE: J.M. Leo and J. Blomen, "A Review of Fuel Cell Technology and IES Applications," *Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications* (Lund, Sweden: Lund University Press, 1989), p. 629.

find use in various applications, including dispersed on-site power plants, cogeneration systems, automobiles and portable generators, as well as centralized power stations. However, technical and economic problems such as reliability, operating performance and cost must be resolved before commercial application of fuel cell systems becomes possible.[22]

5.8.2 Magnetohydrodynamics

Magnetohydrodynamics is a direct burning, high efficiency advanced fossil fuel technology for generating baseload electric power. While this technology holds considerable promise in terms of its efficiency and environmental performance, it is not expected to be commercially available for electric utilities until after the turn of the century.

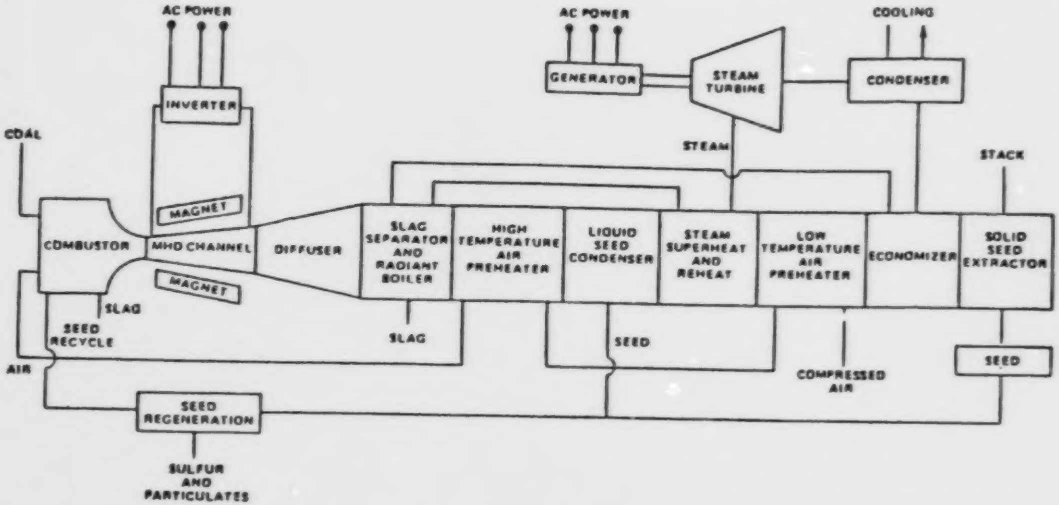
In the MHD system, coal is burned at very high temperatures and the hot combustion gases are chemically treated with a seed material (typically a potassium compound) to increase electricity conductivity. Direct current electrical power is produced when the flowing hot gases pass through a magnetic field created using superconductors.

The energy in the hot gas that emerges from the generator is directed into a boiler system to make steam that is used to operate a conventional steam turbine generator. Thus, electrical energy is produced in both the MHD portion of the process, called the topping cycle, and in the boiler system/steam turbine generator, called the bottoming cycle (see Figure 5.8).[23]

It is anticipated that first generation MHD power plants will have efficiencies of 40 to 50 percent (scrubbers not required) and mature plant efficiencies of 60 percent. In comparison, a conventional coal-fired power plant equipped with FGD scrubbers is 32 to 33 percent energy efficient.[24]

The relative increase in thermal efficiency offered by MHD means less fuel use, less energy for fuel transportation, less mining/reclamation, less cooling water and reduced overall plant effluents for each kW.h of electricity generated. Carbon dioxide per kW.h is as much as 38 percent less than a conventional coal-fired power plant fitted with scrubbers, due to the increased thermal efficiency of the process.[25]

Figure 5.8
MHD Power Cycle


AC POWER
INVERTER
COAL
MAGNET
COMBUSTOR
MHD CHANNEL
MAGNET
DIFFUSER
SLAG
SEED RECYCLE
AIR
SEED REGENERATION
SULFUR AND PARTICULATES
AC POWER
GENERATOR
STEAM TURBINE
COOLING
CONDENSER
STEAM
STACK
SLAG SEPARATOR AND RADIANT BOILER
HIGH TEMPERATURE AIR PREHEATER
LIQUID SEED CONDENSER
STEAM SUPERHEAT AND REHEAT
LOW TEMPERATURE AIR PREHEATER
ECONOMIZER
SOLID SEED EXTRACTOR
SLAG
SEED
COMPRESSED AIR
SEED

SOURCE: California Energy Commission, *Energy Technology Status Report*, Figure 17 (Sacramento, California: CEC, October 1988).

Sulphur dioxide emissions are minimal, as the potassium seed material combines with sulphur in the coal during combustion to form potassium sulphate, which is collected as a solid in the downstream part of the plant, processed and reused as seed material. Experimental results also indicate that typical MHD operation coupled with a properly designed downstream boiler could reduce NO_x emissions to 30 percent of the current U.S. New Source Performance Standards requirements.[26]

Magnetohydrodynamics can use coal or other combustible fuels. While primary interest in the United States is in electricity generation using MHD technology with coal, the U.S.S.R. is experimenting with natural gas. The high temperature of combustion products leaving the generator makes it suitable for use as a topping cycle for new and existing steam power plants.[27]

Magnetohydrodynamics is in the development stage--its maturity, potential applicability and economics have not been established and there are drawbacks which must be overcome before it is recognized as a viable supply option for electric power production. It is very capital intensive, requires superconductors that have only reached the laboratory stage of development, and the high temperature combustion could result in high nitrogen oxide emission rates.[28] Despite these drawbacks, MHD affords significant potential for high efficiency and low emissions for electric power utilities beyond the turn of the century.

Footnotes

[1] International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1988), p. 58.

[2] United States, National Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," Vol. II - Emissions and Controls (Washington, D.C.: National Acid Precipitation Assessment Program, 1987) p. 2-6.

[3] International Energy Agency, *The Clean Use of Coal: A Technology Review* (Paris, France: Organisation for Economic Co-operation and Development, 1985), p. 14. See also K. Morgan MacRae, *An Assessment of the Potential for Coal-Derived Syncrudes in Canada*, CERI Study No. 27 (Calgary, Alberta: Canadian Energy Research Institute, June 1988).

[4] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition", 1987, p. 2-16.

[5] Ontario Hydro, *Thermal Cost Review* (Toronto, Ontario: Ontario Hydro, October 1989) p. 62.

[6] United States, Environmental Protection Agency, *Policy Options for Stabilizing Global Climate* (Washington, D.C.: EPA, February 22, 1989), p. VII-132.

[7] Electric Power Research Institute, "Retrofit Strategies for NO_x Control," *EPRI Journal* (March 1987): p. 28.

[8] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 67.

[9] Ibid., p. 68.

[10] International Energy Agency, *The Clean Use of Coal: A Technology Review*, 1985, p. 7.

[11] Dr. Jan Vernon, "Air Pollution Control and Its Impact on Coal Use," *Energy Exploration and Exploitation*, (Essex, United Kingdom: Multi-Science Publishing Co. Ltd., 1988) p. 459.

[12] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 68.

[13] Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls (Draft)* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-42.

[14] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds*

(VOC) in Canada: Work Sub-Group 6.2 Report, Stationary Sources - NO_x, p. 27.

[15] Ontario Hydro, *Thermal Cost Review*, October 1989, pp. 35-36.

[16] Coal Association of Canada, *Brief on Global Warming to House of Commons Standing Committee on Environment* (Calgary, Alberta: Coal Association of Canada, December 14, 1989).

[17] For information on recent advances in gas turbine technology, see California Energy Commission, *Chemically Recuperated Gas Turbine - Staff Report Draft* (Sacramento, California: California Energy Commission, January 1990) and Robert H. Williams and Eric D. Lawson, "Aeroderivative Turbines for Stationary Power," *Annual Review of Energy 1988*, (Palo Alto, California: Annual Reviews, Inc., 1988) pp. 429-489.

[18] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-43.

[19] United States, U.S. Congress Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s* (Washington, D.C.: U.S. Government Printing Office, July 1985), p. 103.

[20] Ibid., p. 629.

[21] United States, U.S. Congress Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s*, (Washington, D.C.: United States Government Printing Office, July 1985) p. 103.

[22] T. Sugimoto, "Prospects for the Future for the Development of Solar Cell, Fuel Cell Systems, Advanced Batteries and Electric Energy" in *EPRI Proceedings 1989 Conference on Technologies for Producing Electricity in the Twenty First Century*, San Francisco, California: October 30-November 2, 1989, p. 5

[23] Fred Walter and J. M. Sherick, *Coal-Fired MHD Generation - Status and Designs* (Butte, Montana: Montana Power Company and MSE Inc.), p. 3.

[24] Ibid.

[25] Ibid.

[26] Ibid.

[27] California Energy Commission, *Energy Technology Status Report: Report Summary*, Report P500--88-003 (Sacramento, California: CEC, October 1988) pp. 40-115.

[28] United States, Environmental Protection Agency, *Policy Options for Stabilizing Global Climate*, 1989 p. VII-134.

Chapter 6

ALTERNATIVE STRATEGIES TO LIMIT ATMOSPHERIC EMISSIONS

6.1 Introduction

Having reviewed specific supply-side technologies, it is useful to briefly describe some new, broadly based alternatives which have been suggested for controlling atmospheric emissions from power generation. As control of nitrogen oxide (NO_x) and sulphur dioxide (SO_2) has been largely addressed as a technological fix, most of these new alternatives deal with carbon dioxide (CO_2) reduction and are more recent and more preliminary in nature. As a result, considerable work is required to determine if these options will be effective and how much they will cost. This determination is important as alternatives must be ranked by cost and their relative impact to be of use in determining an optimal, least-cost strategy for reducing emissions by a given amount.

For example, the increasing marginal costs of CO_2 reduction in Canada suggest that a time will come when it will be most cost-effective to put money into reducing CO_2 emissions in the developing countries (LDCs). Sale of Canadian technology and outright grants supporting increased efficiency in LDCs are options which might be considered. At what point it becomes appropriate to spend these funds versus the allocation of greater funds for advancement of Canadian technology is a question which remains to be addressed.

While technological solutions to NO_x and SO_2 may or may not reduce CO_2 emissions, depending on the overall efficiency of the control technology, such is obviously not the case where reduction of CO_2 is the primary criterion. Actions taken to reduce CO_2 will also reduce sulphur dioxide and nitrogen oxides. It is instructive, therefore, to examine the effectiveness of various alternatives postulated for CO_2 reduction as these strategies will reduce atmospheric emissions of all forms.

6.2 Mitigation Strategies

Various options have been suggested to reduce CO_2 emissions from the electric power sector. These include:

(1) increase efficiency of primary generation using improved techniques in electronic controls, heat recovery, and environmental control systems; modify units to use new technologies (e.g., add advanced conversion systems such as combined cycles and fuel cells);

(2) implement demand-side management (DSM) programs and improve end-use electrical efficiency via such techniques as time-of-use rates, new appliance efficiency standards and revised building codes;

(3) pursue integrated energy efficiency improvements through, for example, the deployment of cogeneration technology with waste heat utilization;

(4) convert power plants to high hydrogen content fuels (e.g., coal to gas);

(5) remove CO_2 from effluents by end-of-stack removal techniques for permanent disposal;

(6) shift to non-fossil fuel electricity production, through renewable and nuclear alternatives;[1]

(7) increase interregional electricity trade;

(8) use afforestation to sequester CO_2; and

(9) transfer energy efficient technology to LDCs to reduce the growth in their production of carbon dioxide, sulphur dioxide and nitrogen oxides.

6.2.1 Power Plant Efficiency

6.2.1.1 Existing Power Plant Efficiency

The scope for improving efficiency within existing power plants varies depending upon the size, age and type of equipment and the modes of operation of the plants. Some efficiency improvements seem possible, although it appears they would not exceed 1 to 2 percent and would be costly to implement. Consequently, limited funds available for pollution reduction would be better spent on other alternatives for CO_2 reduction.[2]

6.2.1.2 Increased Generating Efficiency

Current methods to convert thermal to electric energy have an efficiency in the order of 35 percent. Advanced technologies offering greater conversion efficiencies of fossil fuels to electricity will reduce the amount of fuel that is needed to generate a kW.h of electricity. For example, combined cycle generation with coal gasification (IGCC) offers near-term prospects of close to 45 percent efficiency. In the longer term, combined cycle-fuel cell generation affords prospects of over 50 percent efficiency. Thus, the same amount of electricity would be produced with almost half as much fossil fuel consumption. While the cost of electricity could rise somewhat if these technologies were adopted, the increase promises to be substantially less than that which would be required if technological options for CO_2 removal and disposal were required.[3]

6.2.2 End-Use Efficiency

Demand-side management refers to measures taken to reduce the demand for electricity through improvements in end-use efficiency and also includes programs designed to shift demand from peak to non-peak periods. Demand-side management provides electric utilities with the ability to reduce emissions by reducing peak and/or overall demand for fossil-fuelled generation, thereby delaying the need for additional generation and transmission capacity.

Significant opportunities for end-use efficiency gains in the electricity sector include the development and application of products, services and techniques such as: (1) energy efficient space heating and cooling systems; (2) insulation; (3) energy efficient windows and doors; and (4) energy efficient lighting, motive power and air handling systems.[4]

In the United States, utility efforts to modify customer consumption patterns have increased steadily in recent years. For example, the latest survey conducted by the Electric Power Research Institute (1988) shows that almost 4 million appliances are being directly controlled by utilities.[5] The application of DSM programs has been spurred recently by utilities foraging into Least Cost Planning (LCP), largely at the insistence of U.S. state regulatory bodies. Least Cost Planning refers to planning by a utility in such a manner as to select the least cost strategy from a possible portfolio of both supply- and demand-side management options. At least 43 states either have functioning LCP strategies or are considering, developing or implementing a planning process that will help find the appropriate balance of new generating facilities and demand-side management. Least cost energy planning, drawing on greater use of utility efficiency programs, is also featured in some of the global warming bills now before the U.S. Congress.[6]

While the potential for DSM dawned somewhat later in Canada, many Canadian utilities recognize end-use efficiency improvements as the single most important and cost-effective strategy for reducing CO_2 emissions. In Ontario, for example, demand management programs are expected to meet 60 percent of all growth in electricity demand over the next ten years.[7] Ontario Hydro's current DSM program targets electricity savings of 28 150 GW.h by 2005. If these planning targets are met, savings in electricity consumption will result in an impressive reduction in emissions--52 kt of NO_2 and 20.6 Mt of CO_2 annually by 2005. Other utilities across Canada, notably in British Columbia and Quebec, are also recognizing the potential of conservation and load management. Indeed, **country-wide DSM targets to the end of the century exceed 12 000 MW, putting DSM on a mega-project status in terms of overall impact.**[8]

Additional indications of the electricity savings and emissions reduction potential of demand-side management and conservation programs are cited in recent figures prepared as background to the Draft NO_x/VOCs Management Plan. For example, total residential electricity savings in 2005 are estimated at 41.4 TW.h with a corresponding reduction in carbon dioxide emissions of 34 Mt. Electricity savings resulting from DSM in the commercial sector were projected at 206.5 TW.h, yielding a cumulative emissions reduction impact of 379 kt of NO_x and 152 Mt of CO_2 for the 1990 to 2005 period.[9]

While the diversity of Canada's industrial sector prevents aggregate, Canada-wide analysis of DSM program savings, the potential is enormous--some 41 percent of Canada's electric demand is attributable to industry. Electrical efficiency in this sector can be applied to: (1) electrical efficiency improvement technology, which contributes to load reduction and emissions reduction (e.g., high efficiency electric motors); (2) cogeneration, which involves self generation or generation displacement and contributes significantly to emissions reduction by utilizing waste heat; and (3) the use of electrotechnologies offering high efficiencies. The greatest opportunities for improvements in the industrial sector are to be found in motor technologies, including high efficiency motors and variable speed drives. Lighting is the next largest source of potential.[10]

Indicative of the growing belief in the cost effectiveness of end-use efficiency programs was Environment Canada's statement that a combination of strong DSM programs and new energy efficiency performance standards could reduce electricity demand by 20 percent of currently projected levels by 2005.[11] However, a target 15 percent reduction of electricity demand by 2005 was recommended in the Draft NO_x/VOCs Management Plan to allow room for uncertainties and for the different stages of development of current utility DSM programs across Canada. Instead of the annual growth rate of 2.2 percent (1990 to 2005) forecast by utilities, this 15 percent target effectively reduces Canadian electricity growth over the 1990 to 2005 period to just over one percent.

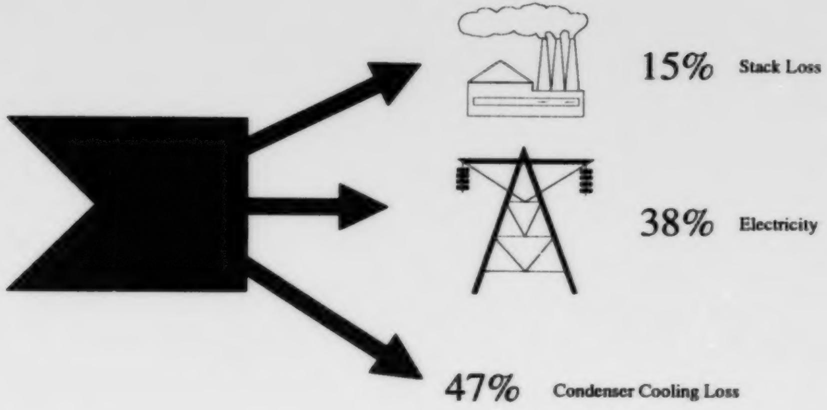
The main impediments to greater application of DSM are institutional and behavourial. As a society, we are skilled at increasing energy supplies, but we have very little experience in moderating individual consumer demand for electricity.[12] It is much easier to coordinate the construction of a single, large power plant than to influence the behavior of a large and diverse number of consumers. Some analysts suggest that a much more proactive stance including, for example, the direct installation and financing of energy efficient equipment is required if efficiency programs are to be more effective than has been the case to date.[13,14]

6.2.3 Integrated Energy Efficiency (IEE)

Integrated energy efficiency refers to improving not only the efficiency of the energy generator itself but also the way energy moves and how it is used. Integrated energy efficiency often involves integrating more than one use, as in district heating/cooling, energy storage, and energy cascades such as combined cycles and cogeneration.[15] In a conventional thermal generating plant, conversion efficiency of fuel to power is about 38 percent (maximum); the rest of the fuel's energy content is vented up the stack (15 percent) and lost to the condenser cooling water (47 percent; see Figure 6.1). However, advanced processes using a combined cycle (e.g., IGCC or pressurized fluidized bed combustion (PFBC)) can improve the efficiency of electricity generation to 45 percent, resulting in a 16 percent decline in CO_2 generated (see Figure 6.2).

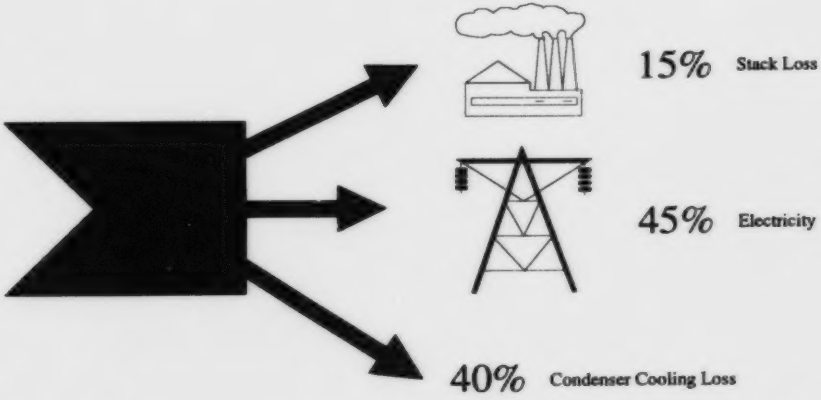
Going one step further, the combined production of heat and power (cogeneration) can markedly increase efficiencies and thereby reduce the amount of pollutants generated. If a district heating/cooling system is coupled to electricity production to utilize the waste heat in the cooling water, the overall efficiency can be improved to as high as 82 percent (see Figure 6.3). An even better scheme to integrate and maximize energy efficiency is to couple an advanced combined cycle process such as IGCC or PFBC to the district heating/cooling application. While energy storage may not decrease the

Figure 6.1
Conventional Thermal Electricity


15% Stack Loss
38% Electricity
47% Condenser Cooling Loss

SOURCE: A.C.S. Hayden, June 1990.

Figure 6.2
Advanced Generation
Combined Cycle (IGCC or PFBC)

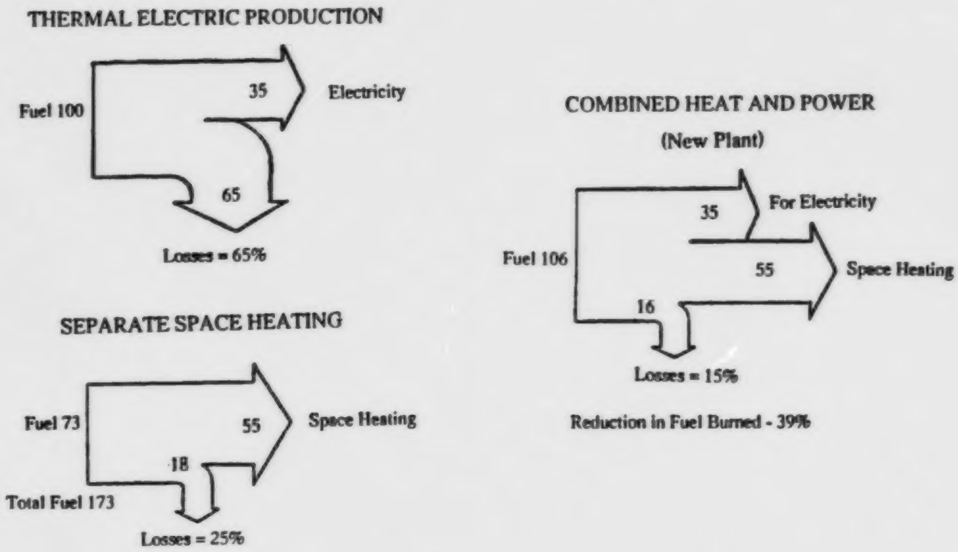

15% Stack Loss
45% Electricity
40% Condenser Cooling Loss

16% Less CO_2 Emitted

SOURCE: A.C.S. Hayden, June 1990.

Figure 6.3

Advantages of Cogeneration


THERMAL ELECTRIC PRODUCTION
Fuel 100
35
Electricity
65
Losses = 65%
SEPARATE SPACE HEATING
Fuel 73
55
Space Heating
18
Total Fuel 173
Losses = 25%
COMBINED HEAT AND POWER
(New Plant)
Fuel 106
35
For Electricity
55
Space Heating
16
Losses = 15%
Reduction in Fuel Burned - 39%

SOURCE: Energy, Mines and Resources Canada.

amount of energy consumed, it can substantially improve load factors, both diurnal and seasonal. If cogeneration were widely practised, enormous amounts of fossil fuels, presently used for space heating and for the production of electricity for air conditioning, could be saved and atmospheric pollutants significantly reduced.[16]

Although Canadian electric utilities acknowledge the savings afforded through integrated energy use, they assert these opportunities are not in their mandate. Because the environmental benefits can be substantial, alternatives to conventional "utility" corporations may be required. "The full realization of these benefits will not take place until the potentials are recognized and a major shift in perspectives takes place, along with the development of energy utilities, rather than just single commodity fuel or electric utilities, as major players in Canada's energy/environment future."[17]

6.2.4 Shifting Fuels

A shift to hydrogen-rich fuels would involve much greater use of natural gas than at present. Greater use of gas would tend to reduce CO_2 emissions, as natural gas is estimated to produce about 45 percent as much CO_2 per kW.h as coal on a complete fuel cycle basis. However, a concern with the increased use of natural gas for Canadian electric power generation is the relative price of gas compared to coal over the next twenty years. Although gas prices are currently depressed, they can be expected to increase with rising demand. The date of such an increase is unknown, but is likely within the useful lifetime of a power plant.

A presentation by TransCanada Pipeline Ltd. (TCPL) to the Canadian Energy Research Institute's (CERI) June 1990 conference "Electric Power Planning in the 1990s" emphasized the fact that there are limited natural gas reserves available for electric power production in Canada.[18] Sufficient natural gas is only available to fill a small portion of the expansion plans of the Canadian electrical industry and will inevitably be used in those applications for which it is best suited--i.e., certain niche markets.[19]

An attractive option gaining considerable interest in the more densely populated regions in the United States and Europe is the use of municipal waste as a source of power. Municipal solid waste is the source of many pollutants and its effective disposal is becoming increasingly difficult and expensive. Moreover, sanitary waste landfill sites are a major source of methane emissions, a greenhouse gas some 25 times more powerful than CO_2. Advanced combustion techniques, such as fluidized bed combustion or IGCC, offer the best ways of rendering these wastes sterile, eliminating methane emissions associated with landfill and reducing solids disposal by one to two orders of magnitude.[20] At the same time, the significant amounts of energy inherent in the waste streams can be utilized. If district heating could be appended to this form of electricity production, overall efficiencies would rise significantly and greenhouse gas emissions would fall dramatically. In fact, this strategy is the basis of Texaco's plans to renew IGCC operations at the Cool Water plant using a mixture of sewage sludge and coal. Other U.S. jurisdictions are examining the co-processing of waste and coal into electricity in order to allay pressing concerns over solid waste disposal and the increasingly stringent environmental constraints imposed on the production of electricity.

6.2.5 CO_2 Scrubbing and Disposal

The recovery of CO_2 from power plant stack gases coupled with innovative disposal techniques has also been suggested. For example, CO_2 can be recovered from flue gas with existing scrubbing technology followed by liquefaction and transmission to eventual disposal or reuse. Unfortunately, as flue gas contains only small amounts of CO_2, recovery using existing technology is prohibitively expensive. Increases in electricity costs as high as 80 percent for CO_2 recovery have been estimated in the United States and figures for Alberta indicate a doubling in the current price of electricity. On the whole, it appears that collection and disposal of CO_2 from existing units is economically unattractive, though local applications such as enhanced oil recovery using CO_2 from an IGCC water shift process may ultimately prove economic.[21]

Whatever the final cost, CO_2 recovery for power plants seems very expensive considering the total reduction in CO_2 to be achieved relative to this sector's contribution to total emissions of CO_2. This is especially relevant as the final fate of the CO_2 recovered is uncertain, given that there is no guarantee that it will not eventually find its way into the atmosphere.[22]

6.2.6 Switching to Non-Fossil Energy

If public opposition to **nuclear power** could be changed, nuclear generation might prove a viable alternative to new fossil-fired power generation. However, even were this to occur, the time frame required to establish the labour capability to build and operate these plants could be in the order of fifteen to twenty years. In addition, large cooling water requirements would limit the viability of nuclear power for many locations in western Canada. Prospects for combined cycle plants based on coal gasification and fuel cells seem a more promising and more timely alternative to investing in nuclear power for western Canada. Research, development and demonstration applied to western Canada coal utilization will, moreover, have export potential to coal-hungry developing countries, whereas foreign orders for CANDU technology have not been near what many had hoped.

Hydroelectric power will remain the primary form of Canadian electricity generation beyond the turn of the century but costs are rising as increasingly marginal sites are brought into production. Moreover, increasing public opposition (aesthetics, electromagnetic (EMF) effects, environmental disruption) to hydro development and the long distance high voltage transmission lines needed to move hydroelectric power from northerly sites to load centres make hydro less favoured than was the case in the past.

The opportunities for **solar energy** are improving with advances in photovoltaic devices but it still remains far more costly than conventional electricity--estimates exceed 25 cents per kW.h. Technological improvements in efficiency could foreseeably lower the cost of solar electricity to 10 cents per kW.h by the mid-1990s, though efficiency and cost would vary considerably by geographical location. This may have some application to dispersed generation towards the turn of the century.[23] Wind power may also prove viable for dispersed electricity generation in some parts of Canada.

6.2.7 Increased Electricity Trade

As CERI concluded in *Critical Issues In Electric Power Planning in the 1990s*, opportunities exist for greater interregional electricity trade. While most of this trade would flow south due to the greater revenues accruing to export of Canadian electric power to the United States, the point may be a moot one. If Canadian electricity exports reduce SO_2 and NO_x from U.S. power plants which would otherwise fall on eastern and central Canada, then all parties benefit. These Canadian exports would also reduce CO_2 emissions from U.S. electric power production.

Greater synergies within Canada's utility system also bear examination. For example, Canadian utilities can use demand management programs and/or new non-fossil generation to create excess capacity for export. If this export reduces SO_2 and NO_x

emissions from U.S. power plants, then there will be a positive effect on emissions levels in key areas of Canada such as the Windsor-Quebec City corridor and greater Vancouver area.[24] Greater interregional trade within Canada could also reduce emissions--e.g., from British Columbia to Alberta and from Labrador to New Brunswick.

The advent of superconductivity could also dramatically change the face of electricity trade and load management within North America as electric power could be economically shunted greater distances with less power loss, taking advantage of time zone differentials in peak matching. Unfortunately, it appears that it will be a long time before this technology is commercially proven.

6.2.8 Afforestation

Afforestation has been widely suggested as a CO_2 mitigation strategy. Growth of vegetation removes CO_2 from the atmosphere by photosynthesis. The fact that new growth is most efficient at absorbing CO_2 suggests that mature trees should be harvested to store the carbon taken up from the atmosphere. However, this evergreen approach to CO_2 mitigation also faces limitations. The forest acreage required to absorb CO_2 emitted from major sources such as thermal power stations is very large. For example, to absorb the 5 billion tons of CO_2 emitted every year by global fossil fuel combustion would require planting 7 million square kilometres of trees--an area the size of Australia, or about as much as all of the tropical forest cleared by human activity up to the present. To offset the emissions of a single, 500 MW coal-fired power plant would require planting a forest of about 1000 square miles.[25]

Moreover, to achieve long-term CO_2 removal, the harvested wood would have to be stored permanently to avoid decomposition, as this would release both CO_2 and methane to the atmosphere. Harvesting the wood and using it for electric power production might prove economic in some instances and would displace fossil fuels, resulting in a net decrease in CO_2 levels.[26] The costs of afforestation are lower than those of any other method of CO_2 sequestering now being considered.[27]

6.2.9 Technology Transfer

While employing strategies comprised of the various options noted above could greatly help reduce CO_2 emissions and other atmospheric pollutants in the developed countries, the question remains of what actions to take in the developing world where extremely limited capital is available for environmental enhancement.

Current projections indicate that these countries will account for about 60 percent of total world-wide CO_2 emissions by the middle of the next century, compared to only 20 percent today. As the growth in many other greenhouse gases is directly related to population growth, these countries will also constitute major sources of other greenhouse gases, such as methane. Deforestation in countries such as Brazil has already resulted in a significant fall in the world's "lung capacity". In short, the industrialized world might be able to stabilize and maybe even reduce its CO_2 production through efficiency improvements and fuel switching, but developing countries will continue to increase their use of fossil fuels and production of atmospheric pollutants.

> "...this is an area where developed and developing countries have a clearly discernible common interest...it will be more clearly in the industrialized countries' interests to provide developing countries with the ability to mitigate the growth of their contribution to atmospheric CO_2. Indeed, there will likely come a time when incremental energy efficiency increases for both electricity generation and end use will be much cheaper to obtain in the developing world. This suggests that an important part of any strategy to mitigate global climate warming will be to facilitate transfer of technologies to the developing world."[28]

The developing countries, by and large, are prevented by economic reasons from having access to state-of-the-art technologies. According to World Bank estimates, the capital requirements of developing countries for electric power alone will total 1.0 trillion dollars during the next decade.[29] System maintenance is also a problem for these countries, resulting in lower than attainable efficiencies. For example, if the OECD countries pushed generation efficiency in the developing world from the high 20s (percent) to the high 30s, the electricity that is today produced with four power plants could be produced from three power plants. Carbon dioxide emissions would fall by a quarter; a proportionate fall in NO_x and SO_2 emissions would also have positive impacts on the regional environment.[30]

At some point, it will be clearly in the industrialized countries' interests to provide developing countries with technologies to mitigate the growth of their contribution to atmospheric CO_2. This suggests that the transfer of energy efficient technologies to the developing world will be an important component of any strategy to mitigate global climate warming. This argument supports greater funding for development of energy efficient coal technologies in Canada and the transfer of this technology to: (1) developing countries in Asia; and (2) environmentally backward countries in eastern Europe.

6.2.10 Limiting World-Wide Population Growth

Almost all discussion on greenhouse gas abatement strategies is directed to the supply side and virtually none to the intrinsic cause of our concern for future levels of greenhouse gases--the world's burgeoning population and its energy demands. It seems that analysts have little problem in asserting that we all must make major changes in our lifestyle if we are to be saved from the impending atrocities of global warming, but stop short of the moral-lifestyle question posed by reducing rates of population growth.

Policies aimed at reducing the projected growth in population in developing countries over the next two decades would greatly help stem the growth in greenhouse gases. This is another area where technology transfer from developed to developing countries has merit.

6.2.11 Adapting to Global Warming

As our understanding of the regional impacts of global warming improves over the next decade, so too will our understanding of cost-effective abatement strategies. One such strategy, given little attention to date, is learning to adapt to global warming. Under this general heading would fall such options as increasing the size and structural support of seawalls to protect major urban centres, moving populations inland away from rising oceans, etc. As our knowledge of the regional impacts of global warming improves, such "learning to cope" strategies could become cost-effective, practical considerations. Moreover, given our rather dismal success in solving global resource allocation problems to date, we should start evaluating these strategies immediately.

Options which planners and policy makers might examine include:

- staggering work hours to minimize congestion of our highways and peak use of electricity for lighting and cooking;

- encouraging responsible employees to work at home to reduce peak hour pressures on urban highways and mass transit systems;
- mandating a reduction in packaging of consumer products thereby reducing energy used for packaging and reducing the number of trees required to sequester CO_2;
- banning production and delivery of junk mail and telephone books (paper constitutes 35 percent of landfill) or using these combustibles for electricity generation using IGCC coupled with district heating in city centres;
- evaluating planning codes that push future urban development away from rising lake and ocean water levels;
- increasing inner-city parking charges to encourage multi-passenger trips and use of mass transit;
- taxing gasoline and diesel to promote both the production and the purchase of energy efficient automobiles and trucks--with the tax revenue earmarked for cleaning up existing environmental problems and to finance research and demonstration of new, more energy efficient technology; and
- restricting non-essential passenger cars from the inner city.

The options available are only limited by one's imagination and the costs and impacts of alternative actions and/or inaction. A number of jurisdictions across Canada--Ontario, Alberta, and Saskatchewan--are canvassing the public for their opinions on what they perceive as practical strategies. As the future unfolds, new options and variations will allow us to creatively manage and cope with the regional consequences of global warming.

6.3 Synopsis

Various methods to reduce net CO_2 emissions exist and the cost effectiveness of these options should be compared in order to determine an optimum strategy for CO_2 emission reduction in the short and long term. In the short term, it appears that energy conservation, cogeneration and afforestation would be more economic than CO_2 recovery and disposal systems. The development of fuel cells and sale of Canadian clean coal technology to countries in the developing world seem strong contenders for CO_2 mitigation in the mid to long term.

In order for conservation, DSM and cogeneration to be evaluated on an equal footing, the costs of these options must be allowed in rate base and amortized over periods of time comparable to conventional forms of generation such as hydro and nuclear power. While this is not of major concern in those jurisdictions where provincially-owned utilities supply electric power, it is of utmost importance in those regions where private utilities produce electric power. Least cost planning must be actively supported across Canada by provincial regulators if end-use efficiency programs are to provide a more balanced share of Canadian electricity demand/supply. As noted above, the potential savings across the residential, commercial and industrial sectors of Canada's economy are enormous, as are the potential reductions in atmospheric emissions of SO_2, NO_x and CO_2.

In the broader context, it is important to recognize that greenhouse warming is a global issue--to solve it will require global solutions. There will come a point at which it is more cost effective to assist developing countries in their efforts to reduce CO_2 emissions than to attempt further reductions in Canada's emissions. A strategy which enunciates where and how Canada can best reduce atmospheric emissions is clearly called for. The next chapter attempts to address this question in the context of a decision-making framework (ELGEM) applied to Canadian electric power development.

Footnotes

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[3] Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies," 1989, p. 7.

[4] Canada, Department of Environment, *The Role of Energy Efficiency, Fuel Switching: Lifestyle Changes with Emissions Management of Nitrogen Oxides and Volatile Organic Compounds*, Background Report to Draft NO_x/VOC Management Plan, (Ottawa, Ontario: March 1, 1990), pp. 176-181.

[5] Joseph A. Van den Berg and Clark W. Gellings, "Demand Side Management: The United States' Perspective," Edison Electric Institute/Electric Power Research Institute, Presentation at the Canadian Energy Research Institute *Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990, p. 2.

[6] Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies," 1989, p. 8.

[7] Dane B. MacCarthy, "Demand Management in Canada," Ontario Hydro, presentation at the Canadian Energy Research Institute *Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990, p. 7.

[8] Canada, Department of Environment, *The Role of Energy Efficiency, Fuel Switching*, 1990, p. 113. See also Canada. Energy, Mines and Resources, *Electric Power in Canada 1989* (Ottawa, Ontario: Minister of Supply and Services Canada, 1991), p. 101.

[9] Ibid., pp. 151-152.

[10] Ibid., p. 157.

[11] Canada, Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, *Management Plan for Nitrogen Oxides and Volatile Organic Compounds, First Edition, (Draft)* (Ottawa, Ontario: Environment Canada, March 1990), pp. 91-92.

[12] Ibid., section A8-8.

[13] See John B. Robinson, *The Proof of the Pudding: Policy and Implementation Issues Associated with Increasing Energy Efficiency* (Waterloo, Ontario: University of Waterloo, Department of Environment and Resource Studies, November 1989).

[14] Hatch Associates Ltd., *CO_2 Emissions: Perspectives and Future Options for Canadian Electric Utilities and the Coal Industry*, 1990, section A8-8.

[15] A.C.S. Hayden, M. Wiggin, and M.C. Hahn, "The Integrated Energy Utility: A Key to Environmental Enhancement," CCRL/ERL/CANMET, Presentation at the Canadian Energy Research Institute *Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990, p. 4; Personal correspondence from Michael Wiggin, CANMET, August 22, 1990; see also, Arnold P. Fickett, Clark W. Geelings, and Amory B. Lovings, "Efficient Use of Electricity," *Scientific American*, Vol. 263, No. 3, September 1990, pp. 65-74.

[16] Ibid., p. 10.

[17] Ibid., p. 9.

[18] Such is also the case for the planet as a whole. At the current world-wide rate of consumption, coal would last about 1500 years; natural gas would last only 120 years. See William Fulkerson, Roddie R. Judkins, and Manoj Sanghvi "Energy From Fossil Fuels," *Scientific Americcn*, Vol. 263, No. 3, September 1990, pp. 129-135.

[19] David Russell, "The Role of Natural Gas in Canadian Electricity Generation," presentation at the Canadian Energy Research Institute *Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990, p. 3.

[20] A.C.S. Hayden, M. Wiggin, and M.C. Hahn, "The Integrated Energy Utility: A Key to Environmental Enhancement," 1990, p. 9.

[21] Hatch Associates Ltd., *CO_2 Emissions: Perspectives and Future Options for Canadian Electric Utilities and the Coal Industry*, 1990, p. 22.

[22] Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies," 1989, p. 8.

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[26] John Douglas, "Sharper Focus on Greenhouse Science," *EPRI Journal*, June 1990, pp. 12-13.

[27] William Fulkerson, Roddie R. Judkins, and Manoj K. Sanghvi, "Energy From Fossil Fuels," September 1990, pp. 133-134.

[28] Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies," 1989, pp. 27-28.

[29] Ibid.

[30] Ibid.

Chapter 7

CLOSING THE GAP--DEVELOPMENT STRATEGIES FOR NEW COAL TECHNOLOGIES

7.1 Introduction

In order to evaluate all technologies within a consistent framework, a linear programming model (ELGEM) jointly developed by the Canadian Energy Research Institute (CERI) and the Alberta Research Council (ARC) was modified to account for new costing information and emissions data. This planning model also allows an evaluation of the effects of conservation, demand management and electricity trade as electric power options to meet projected electricity demand and satisfy emission guidelines.

The questions we set out to examine included:

- How will utility planning decisions with respect to the nature and timing of new capacity additions be influenced by:
    - The implementation of tighter sulphur dioxide (SO_2) controls;
    - The introduction of a nitrogen oxide (NO_x) reduction program;
    - The introduction of a carbon dioxide (CO_2) reduction program?
- What potential do new coal technologies have for reducing emissions?
- What likely impact will decisions and actions taken in response to environmental concerns have on the future cost of electricity generation in Canada?
- What are the avoided costs of conservation and demand-side management (DSM)?
- What is the cost of reducing CO_2 emissions, nationally and regionally?

At the outset, it is worth noting that global warming could have a pronounced impact on electricity demand and the mix of generating technologies needed to match these demands. For example, global warming could increase electricity demand uncertainties, increase the demand for cooling power requirements, reduce/increase water levels and impact hydroelectric power capabilities, and affect the thermal efficiency of gas turbines and the electrical efficiency of transmission lines. As our understanding of climatic change improves, potential impacts on utility operations should be assessed. However, owing to the current lack of knowledge on the regional implications of global warming, the modelling that we have undertaken does not account for potential changes in Canada's climate and the flowthrough implications on Canada's electrical generation supply.

The comparative costs of scenarios depicted later in the chapter are also understated somewhat, as higher costs will mean higher electricity rates which, in turn, will reduce the demand for electricity. As we were primarily interested in the cost per tonne of emissions reduced, these elasticity impacts were not explicitly considered. Moreover, the elasticity coefficients themselves are controversial. This enhancement could, however, be included in future versions of the ELGEM modelling framework.

As discussed in the body of this report and in the appendices, there are numerous technologies and strategies for limiting emissions of SO_2, NO_x and CO_2. While the list is extensive, many of these technologies do not sufficiently reduce emissions (e.g., NO_x) relative to suggested target levels, whereas others such as fuel cells and magnetohydrodynamics (MHD) look extremely promising, but considerable research is still required before they are proven commercially available for Canadian electric power generation. From the technologies described in this report, we selected integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC), and atmospheric fluidized bed combustion (AFBC) as candidate technologies, owing to: (1) the cost and commercial availability of these technologies; and (2) their potential for meeting stringent emission controls for SO_2, NO_x and, prospectively, for CO_2.

7.2 ELGEM--Canadian Electrical Generating Planning Model

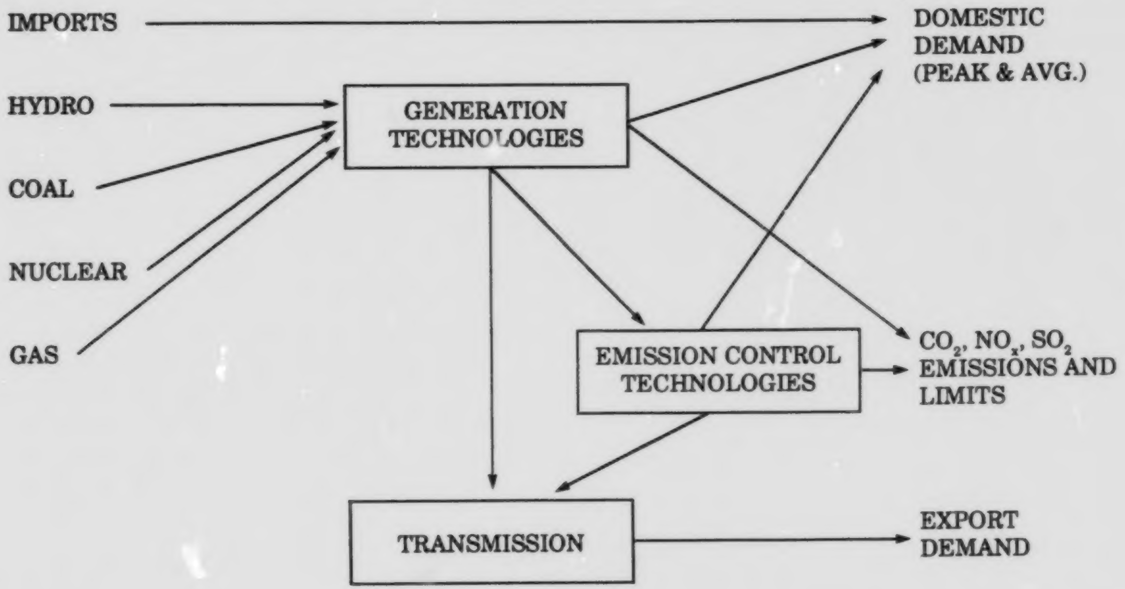
ELGEM is a linear programming model of electricity generation for Canada. Version 1.0 of ELGEM was developed by ARC and CERI to assess the potential savings of greater electricity trade within

Canada and between Canada and the United States. The results of these analyses were presented in CERI Study No. 33, *Critical Issues in Electric Power Planning in the 1990s*, published by the Institute in November 1989. The electric generating technologies, including hydro, nuclear, coal, gas turbine, gas-fired combined cycle etc., are modelled in detail. Long distance transmission lines which link supplies to demand centres are an important part of the supply chain, and are also modelled. The supply options are described in terms of their capital investment schedules, operating characteristics, costs, and emission profiles. The regional aspects of the supply options are captured in the model. The Canadian electric power industry is divided into eight regions, with the Atlantic Provinces treated as one region and the other provinces treated as individual regions. To capture the potential for enhanced international transfers of electricity, the United States is represented as four distinct market regions, in which Canadian power can compete. A simplified schematic for ELGEM for one region is shown in Figure 7.1.

The original ELGEM modelling framework has been modified to undertake our analysis of new coal technologies and their regional cost and environmental impacts. In Version 2.0, the costs of electric generating technologies (e.g., AFBC, PFBC and IGCC) and their air emission factors have been added with the most recent data from the Canadian electric utilities, the Canadian Electrical Association (CEA), the Electric Power Research Institute (EPRI), and the technology developers. Other improvements made to ELGEM include the incorporation of emission control technologies into the modelling framework. This enhancement allows ELGEM to assess how emission control policies in Canada would impact on the electric power sector.

Currently, three levels of emission control, ranging from 30 to 80 percent reductions for each of NO_x and SO_2, have been incorporated, reflecting a range of cost and technology options. These technologies include low excess air, overfire air, low NO_x burner, selective catalytic reduction, flue gas desulphurization, gas reburn, and sorbent injection. Only generic technology costs have been considered, and it is expected that these costs may vary for specific retrofit applications at some plant locations. CO_2 is not controlled in this version, as there are no economically viable options for reducing post-combustion CO_2 emissions. However, regional CO_2 emissions in Canada are reported for each scenario to assess the emissions impact of changes in energy efficiency under the various scenarios (see Appendix C for a more complete description of the ELGEM modelling framework and

Figure 7.1
ELGEM


IMPORTS
HYDRO
COAL
NUCLEAR
GAS
GENERATION TECHNOLOGIES
EMISSION CONTROL TECHNOLOGIES
TRANSMISSION
DOMESTIC DEMAND (PEAK & AVG.)
CO$_2$, NO$_x$, SO$_2$ EMISSIONS AND LIMITS
EXPORT DEMAND

SOURCE: Alberta Research Council.

Appendix D for regional model results of the various scenarios presented below).

The model currently incorporates the Canadian Acid Rain Control initiatives for Canada's seven easternmost provinces as well as recommended New Source Performance Standards (NSPS) for Canada and site-specific NSPS for the Lower Fraser Valley and the Windsor-Quebec City corridor, as presented in Environment Canada's Draft NO_x/VOC Management Plan.

7.3 Canadian Electric Power Development--Technologies, Strategies and Emissions

7.3.1 ELGEM Scenarios

7.3.1.1 Reference Case

The first case (see Table 7.1) depicts national results for SO_2 control only, as contained in Canada's Acid Rain Control program. The objective function, defined as the discounted net present value of capital and operating cost of electric power production in North America over the period, totals $1638.3 billion (1989 $Cdn). That is, the net present value of the costs of electricity generation required to meet projected electricity demand over the period is calculated as $1.64 trillion dollars. Cumulative SO_2 emissions in Canada for the 1988 to 2011 period total 19.8 Mt; CO_2 emissions total 3479 Mt, or over 99 percent of total emissions for the period.

TABLE 7.1

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
REFERENCE CASE--SO_2 CONTROL ONLY

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	3 449.7	19 839	9 990	3 479 529
Objective Function (million $1989 Cdn)			1,638,271	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

7.3.1.2 Base Case

The simulation results presented in Table 7.2 show emissions for a case where NO_x controls are added to the SO_2 case above, as contained in the Environment Canada NO_x/VOC Draft Management Plan. As implementation of NO_x controls similar to those suggested in the NO_x Management Plan appear imminent, this scenario is used as the base case for comparison of subsequent ELGEM model scenarios presented below.

TABLE 7.2

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
BASE CASE--SO_2 AND NO_x CONTROL

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	3 348.9	19 425	8 343	3 376 668
Objective Function (million $1989 Cdn)			1,641,246	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

In order to account for the impact of changes in NO_x regulations and their impact on the Canadian electric power sector, the base case is subtracted from the reference case and results are presented in Table 7.3. Electricity generation in the United States and U.S.-Canada electricity trade are held constant for all scenarios, so that the difference between cases represents the net impact in costs and emissions for the Canadian electric power sector.

Relative to the reference case, total NO_x emissions from the Canadian electric power sector over the 1988-2011 period fall by over 16 percent, with an increase in the cost of Canada-wide electricity generation of $2.98 billion. These results are somewhat higher than the NO_x projections contained in the NO_x/VOC Management Plan. By 2006, ELGEM projects that NO_x emissions would fall by 118 kt per year compared to the estimate of 90 kt per year presented in the Draft NO_x/VOC Management Plan.

TABLE 7.3

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2 REFERENCE CASE MINUS BASE CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	100.8	414	1 647	102 861
Objective Function (million $1989 Cdn)			-2,975.0	
$(1989 Cdn)/Tonne			($28.92)	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

As shown in Table 7.3, expressing incremental emissions as a function of changes in the present value of Canadian electricity generation means that it costs $28.92/tonne to reduce Canadian NO_x emissions to recommended levels. It is interesting to note that the use of new generation technologies, together with a different mix of existing facilities, also results in a reduction in CO_2 and SO_2 emissions--cumulative CO_2 emissions decline by over 100 Mt and SO_2 emissions fall by 0.4 Mt over the 1988 to 2011 period. However, if only acid gas emissions (SO_2 and NO_x) are considered, we can calculate an equivalent cost of $1,443/tonne for acid gas removal ($2,975 million increase in the cost of generation for a reduction of 2061 kt over the 1988-2011 period).

In order to meet the NO_x emission levels suggested in the Draft Management Plan, 1.6 GW of selective catalytic reduction (SCR), 0.3 GW of flue gas desulphurization (FGD) and 8.12 GW of IGCC are required in Ontario. In New Brunswick, Nova Scotia and Prince Edward Island, 0.8 GW of Low NO_x Burners, 0.9 GW of FGD and 2.64 GW of IGCC capacity are required.

7.3.1.3 Demand-Side Management

Table 7.4 displays results for a case where demand-side management/conservation programs are assumed to modify electricity demand such that it falls 20 percent below base case levels by 2009 as suggested in the Draft NO_x/VOC Management Plan. As a consequence of these demand-side programs, the capital and operating costs of installed generating capacity fall dramatically, from $1,641 billion in the base case to $1,475 billion--a total savings of $166 billion. Not unexpectedly, as less generation is required to meet Canadians' electricity demands, a major reduction in all emissions is achieved.

TABLE 7.4

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
DSM/CONSERVATION CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	2 549.1	17 649	7 308	2 574 057
Objective Function (million $1989 Cdn)			1,474,745	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

To show the net impact on Canadian generation costs and emissions, the DSM/Conservation model results are subtracted from those of the base case. As shown in Table 7.5, this scenario results in a net reduction of 800 Mt of CO_2, 1.8 Mt of SO_2 and 1.0 Mt of NO_x, for a total reduction in emissions of 803 Mt over the 1988-2011 period. Assuming all other factors equal between the base case and this DSM scenario, the total benefit in reducing one tonne of emissions by using DSM/conservation programs is $207.45/tonne. **This number can be interpreted as the upper limit on the cost of implementing a DSM program, below which positive net benefits will accrue.** This value assumes, of course, that all emissions--SO_2, NO_x and CO_2--are equally detrimental to the environment.

TABLE 7.5

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
BASE CASE MINUS DSM/CONSERVATION CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	799.8	1 776	1 035	802 611
Objective Function (million $1989 Cdn) $(1989 Cdn)/Tonne			166,501 $207.45	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

In order to satisfy SO_2 and NO_x emission standards under this case, 2.1 GW of SCR and 1.2 GW of FGD are required in Ontario. In New Brunswick, Nova Scotia and Prince Edward Island, 0.1 GW of low NO_x burners, 0.8 GW of FGD and 1.2 GW of IGCC are required.

7.3.1.4 Coal Technology Costs

By comparison, Table 7.6 depicts model results for a case where we evaluate the impact of a 15 percent reduction in the installed capital cost of IGCC, PFBC and AFBC relative to the base case. As shown in Table 7.7, the net impact of this reduction in capital costs is a cumulative reduction in emissions of 10.6 Mt over the 1988-2011 period. The incremental cost of reducing emissions is $85.22/tonne.

TABLE 7.6

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
COAL CAPITAL COST 15 PERCENT LOWER

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	3 339.9	18 486	7 686	3 366 072
Objective Function (million $1989 Cdn)			1,640,343	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE 7.7

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
BASE CASE MINUS COAL CAPITAL COST CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	9.0	939	657	10 596
Objective Function (million $1989 Cdn)			903	
$(1989 Cdn)/Tonne			$85.22	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

Reducing the installed capital cost of new coal technologies by 15 percent brings on IGCC capacity of 4.3 GW in Alberta, 8.12 GW in Ontario and 2.64 GW in New Brunswick, Nova Scotia and Prince Edward Island. To satisfy SO_2 and NO_x emissions guidelines, 1.6 GW of SCR and 0.3 GW of FGD are required in Ontario. A total of 0.9 GW of FGD is added in New Brunswick, Nova Scotia and Prince Edward Island.

7.3.1.5 Coal Technology Efficiency Gain

In Tables 7.8 and 7.9, we present a scenario which assumes that a 10 percent absolute energy efficiency gain is realized over the 1990 to 2010 period for IGCC, PFBC and AFBC technologies. This improvement in efficiency seems realistic given the impressive strides made in gas turbine technology to date, and is more generally an accreditation for the kind of overall improvement expected as a result of wider demonstration of these technologies around the world.

TABLE 7.8

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
COAL EFFICIENCY GAIN CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	3 224.4	18 588	7 692	3 250 680
Objective Function (million $1989 Cdn)			1,639,764	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE 7.9

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2
BASE CASE MINUS COAL EFFICIENCY GAIN CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	124.5	837	651	125 988
Objective Function (million $1989 Cdn)			1,482	
$(1989 Cdn)/Tonne			$11.76	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

As displayed in Table 7.9 the net impact of this increase in efficiency means that aggregate emissions from the Canadian electric power sector fall 126 Mt at an incremental savings of $1.5 billion or $11.76/tonne. To reduce emissions to this level, Ontario requires 2.1 GW of SCR, 0.8 GW of FGD and 7.6 GW of IGCC over the 1994-2011 period. Alberta brings on 4.3 GW of IGCC and New Brunswick, Nova Scotia and Prince Edward Island bring on 0.9 GW of FGD, 2.1 GW of IGCC capacity and 0.47 GW of PFBC (see Figure 7.2).

7.3.1.6 No Nuclear Constraints

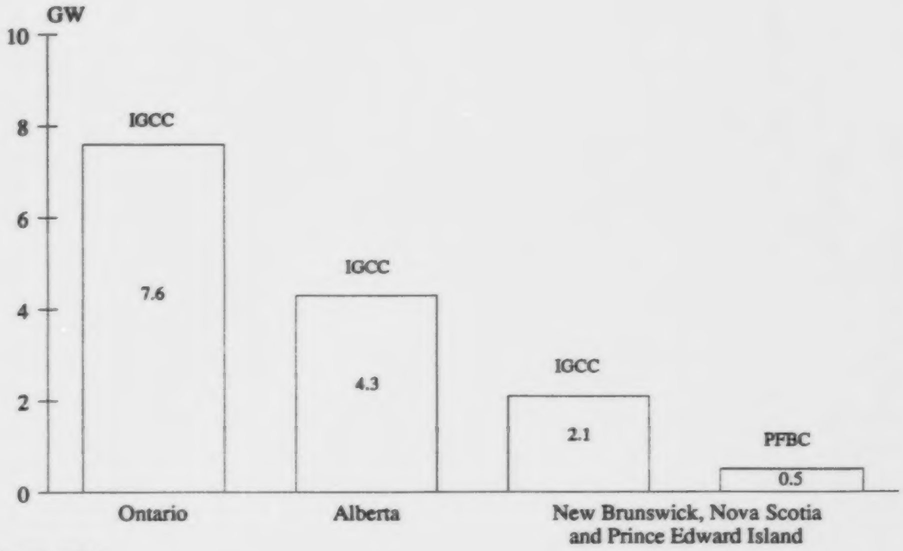
Unlike the previous model scenarios, which assume continuance of the Ontario government's moratorium on nuclear power development, this case (Table 7.10) assumes **no** constraints on development of nuclear powered electricity generation. As shown in Table 7.11, the overall cost of Canadian electricity generation falls $1.8 billion and total emissions fall 180 Mt over the 1988-2011 period.

Assuming that the risks associated with all electricity generating options are equal--e.g., nuclear poses no higher risk of loss of life than, for example, coal-fired generation--the cost of a tonne of emissions saved by nuclear power is $9.78/tonne. To satisfy NO_x and SO_2 requirements, 3.5 GW of SCR, 2.1 GW of FGD and 0.3 GW of IGCC are installed in Ontario. An additional 4.7 GW of nuclear capacity is brought onstream in Ontario over and above base case levels. In New Brunswick, Nova Scotia and Prince Edward Island, 0.9 GW of FGD and 2.6 GW of IGCC capacity is required.

7.3.1.7 Conclusions

Table 7.12 presents summary results for all the ELGEM model simulations discussed above. As displayed in this table, demand-side programs are the most cost-effective means of making a major reduction in CO_2 and in total emissions for the Canadian electric power sector. As the ELGEM model does not account for DSM/conservation supply curves, an estimate of the opportunity value of emissions reduction using DSM programs was inferred by reducing energy demand by 20 percent across Canada and calculating the resulting reduction in the present value of Canadian electrical generating capacity and emissions associated with this capacity. Our ELGEM analysis suggests that DSM/Conservation programs costing less than $207.45/tonne saved should be cost effective for Canada as a whole. The results of the other simulations, which explicitly account for the cost and emissions impact of introducing various technologies,

Figure 7.2
Capacity Added from Coal Technology
Efficiency Improvement by 2009



SOURCE: CERI.

TABLE 7.10

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2 NO NUCLEAR CONSTRAINTS CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	3 168.0	19 824	8 376	3 196 200
Objective Function (million $1989 Cdn)			1,639,481	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE 7.11

NATIONAL TOTAL FOR CO_2, NO_x AND SO_2 BASE CASE MINUS NO NUCLEAR CONSTRAINTS CASE

	Carbon Dioxide Mt/year	Sulphur Dioxide kt/year	Nitrogen Oxides kt/year	Total Emissions kt/year
Total for 1988-2011	180.9	-399	-33	180 468
Objective Function (million $1989 Cdn)			1,765	
$(1989 Cdn)/Tonne			$9.78	

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE 7.12

SUMMARY RESULTS
INCREMENTAL COST AND EMISSIONS SAVINGS[a]

Scenario	CO_2 (Mt/yr)	SO_2 (Mt/yr)	NO_x (Mt/yr)	Total (Mt/yr)	Change in Objective Function (million $1989 Cdn)	Hurdle Price[b] ($1989 Cdn/tonne)
DSM/Conservation	799.8	1.8	1.0	802.6	166,501	207.45
Lower Capital Cost	9.0	0.9	0.6	10.6	903	85.22
Higher Coal Efficiency	124.5	0.8	0.6	126.0	1,482	11.76
No Nuclear Constraints	180.9	(0.4)	(0.03)	180.5	1,765	9.78

SOURCE: Canadian Energy Research Institute.

[a] Net reduction in emissions and present value costs relative to the base case scenario.

[b] The hurdle price can be interpreted as the **maximum** dollar per tonne expenditure which can be justified in achieving the targetted reductions in emissions, under the various scenarios.

show that nuclear power, followed by higher coal efficiency for IGCC and lower coal capital costs for IGCC, are the most effective means of reducing emissions.

While these results support popular assessments undertaken to date, it is important to note that the ELGEM results presented above assume that a tonne of NO_x, SO_2 or CO_2 is equally harmful to the environment. However, given that CO_2 accounts for over 99 percent of total emissions from Canadian electric power production, these results could more accurately be thought of as representative costs to reduce CO_2 emissions from Canadian electric power production.

While it is exceedingly difficult to assess the relative impact of SO_2, NO_x and CO_2 emissions on the environment and the economy, such a comparison is important for the determination of the funds to be assigned and for the design of programs to be undertaken to reduce emissions. For example, Figure 7.3 displays results of the cost per tonne of emissions reduction for three different valuations of the relative environmental impact assigned to a tonne of CO_2 versus a tonne of SO_2 and NO_x. Figure 7.3a displays the ELGEM results described above--in effect the cost per tonne of CO_2 reduction, as CO_2 accounts for over 99 percent of total emissions. If we assume that a tonne of CO_2 was 1/10 as harmful to the environment as a tonne of SO_2 and NO_x, the relative costs of the various strategies would be as shown in Figure 7.3b--nuclear has a slight cost advantage over higher coal efficiency. If we could support the position that a tonne of CO_2 was only 1/15 as harmful to the environment as acid rain, then increasing the efficiency of IGCC and nuclear power are equal in terms of their relative costs and emissions reduction potential (see Figure 7.3c). Reducing this CO_2 ratio further results in IGCC being more cost effective than nuclear power. It is interesting to note that, even at this 1/15 ratio, CO_2 emissions still comprise over 85 percent of total emissions from Canadian electric power production.

While this form of static analysis is interesting, all technologies--DSM, clean coal technologies and nuclear power--will play a part in reducing atmospheric emissions from Canadian electricity production. While DSM/conservation programs have the most dramatic impact, the question of cost and deliverability bear important consideration. Fortunately, the implementation of DSM/conservation programs is starting to take place in Canada. These actions will help to determine the most cost-effective demand-side programs together

Figure 7.3

CO_2 Impact

Figure 7.3a

CO_2 Value of 1

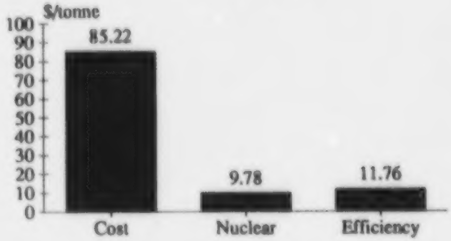


Figure 7.3b

CO_2 Value of 1/10

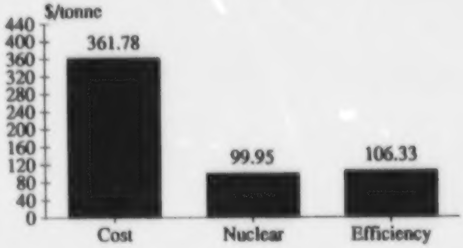
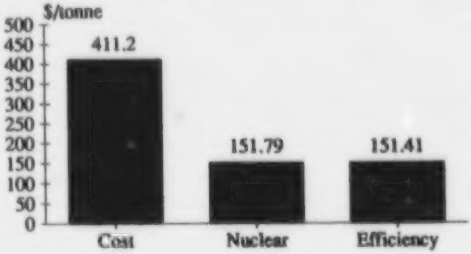


Figure 7.3c

CO_2 Value of 1/15



SOURCE: CERI.

with the most effective mix of complimentary technologies--hydro, nuclear and fossil-fuelled.

Chapter 8

CONCLUSIONS AND RECOMMENDATIONS

8.1 Introduction

New coal technologies hold considerable promise for improved electrical generating efficiency in an environmentally responsible manner. However, most studies do not compare these technologies with competing electric power technologies, such as hydro and nuclear, in a consistent framework which accounts for how **all** might contribute to Canada's future electric power requirements.

The intent here was to examine the cost of meeting proposed reductions in carbon dioxide (CO_2), sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions, and evaluate how new coal technologies might contribute to meeting these emissions reductions. The objective was to provide policy makers and the Canadian public with an objective, independent, and robust assessment of the potential costs of new coal technologies and their contribution to reducing atmospheric emissions in the Canadian electric power sector.

An important ancillary focus is an examination of the regional implications on electric power production and technology mix. In effect, we set out to determine the least-cost technology mix required to meet Canada's future demand for electricity, under constraints imposed by domestic and international concerns with the environment.

This report summarizes work undertaken by the Canadian Energy Research Institute (CERI) in recognition of a building sense of urgency regarding the consequences of atmospheric pollution and the need to dispel some rather common misunderstandings about the current and future impact of coal in Canadian electric power production.

8.2 Planning for Uncertainty

The size and timing of additions to Canadian generating capacity and the ability of utilities to respond to increasingly stringent environmental regulations will depend on Canadians' demand for electric power. For utilities, uncertainty regarding future trends in electricity consumption complicates the planning process and proposals for more stringent environmental legislation further complicate the forecasting of electricity demand and the determination of the least-cost supply mix needed to economically match the electricity requirements of Canadians.

To deal with this uncertainty, electric utility planning strategies are increasingly focussed on ways to maximize **flexibility** in electricity supply and the ability to respond to unexpected demand developments. These efforts include:

- reducing the time-lag between the decision to proceed with a new capacity addition and the in-service date of the facility;
- streamlining the regulatory and planning processes;
- utilizing generating facilities (such as combined cycle plants or natural gas-fired units) that take considerably less time to construct than large hydroelectric stations and nuclear power plants;
- lobbying government to undertake **quality** analyses of the impacts and costs on new regulations, so that Canada's economy is not adversely affected by legislation which places Canadians at a comparative disadvantage in the world economy; and
- improving public and media dialogue to facilitate new utility expansion.

Electric utilities in some regions are also evaluating the enhanced flexibility of greater reliance on demand-side management (DSM), interregional electricity trade and non-utility generation (NUG).

CERI Study No. 33, *Critical Issues in Electric Power Planning in the 1990s*,[1] published by the Institute in November 1989, concluded that new additions to Canadian electrical generating capacity could range from 23 700 to 37 000 MW by the turn of the century, depending on assumed load demand growth. This means that some 3000 to 4000 MW of new electrical generating capacity would have to be added every year during the 1990s--a striking development when compared to Canada's historical additions to electrical generating capacity.

The magnitude of this increase in electrical generating requirements underscores the importance of **flexibility** in utility planning. Public calls for stricter environmental controls place increasing emphasis on efficient production and end-use of electric power. New, more efficient technologies which reduce environmental impacts are fundamental, and are under development by utilities and research agencies across Canada.

Although Canada has lagged the United States and some European countries in looking to conservation, non-utility generation and various other demand-side programs to moderate the growth in electricity consumption, the picture is changing. Ontario, Quebec and British Columbia, for example, are initiating demand-side programs which will offset a considerable percentage of their forecast supply requirements.

8.3 Emission Control Technologies

The production of energy, regardless of the source, has potentially adverse impacts on the environment. These arise at each stage of the fuel cycle--e.g., alienation of land; solid, liquid and gaseous emissions; and environmental impacts, such as oil spills during energy transportation. Despite these impacts, the greatest current source of public concern over the environmental impacts of energy use and production relates to atmospheric emissions produced by fossil-fuel combustion.

The combustion of fossil fuels ranks second as a source of electricity generation in Canada and produces significant atmospheric emissions of SO_2, NO_x, and CO_2. Growing public awareness of how these emissions contribute to acid rain, global warming and the deterioration of local air quality has become the driving force behind interest in greater energy efficiency and Canada-wide government examination of more stringent emissions regulations. Regulations enacted to control emissions will affect the operation and utilization of existing fossil-fuelled generating stations, have an important bearing on technologies deployed in Canadian electric power generation, impact the demand for electricity, and exacerbate planning uncertainty for Canadian electric utilities.

Over the last decade, technologies for the control of emissions from coal have progressed considerably with improvements in coal-cleaning processes, advances in fuel combustion, and in the cleaning of exhaust gases. The term clean coal technologies is commonly used to refer to this set of new systems and processes that produce fewer air pollutants than conventional combustion methods. As CO_2 has only recently become of interest, technological developments have largely focussed on control of particulates, SO_2 and NO_x.

Control of pollutants released in the combustion of coal can be achieved in several ways:[2]

- Particulate emissions can be captured after combustion by electrostatic precipitators and bag filter systems.
- Sulphur dioxide emissions can be reduced prior to combustion by switching to low-sulphur fuels or by removing sulphur from the coal (e.g., by coal washing or coal gasification); during combustion; or after combustion by treating the flue gas.
- Nitrogen oxide emissions can also be reduced by combustion modification techniques or following combustion by flue gas treatment devices.

Other techniques for reducing the sulphur content of coal used in the generation of electricity include coal switching, coal gasification, coal liquefaction and coal-oil co-processing. Switching to low-sulphur coal may be cost effective in some situations; however, there are technological constraints to using low-sulphur coal in utility boilers designed to burn higher-sulphur coal. Upgrading of particulate control devices may be required and coal handling equipment may also require upgrading to compensate for the greater quantities of lower heat content coal required to generate an equivalent amount of electricity. These factors add to the cost of generating electricity and may lead to derating of the boiler.[3]

Other pre-combustion treatments, such as the conversion of coal to gas or liquid fuels, offer the possibility of using coal more cleanly. For example, the development of gasification processes to produce synthetic gas for the combined cycle generation of electricity (IGCC) looks extremely promising. Coal liquefaction and coal-oil co-processing remain longer term options which result in cleaner use of coal, primarily for transportation fuels.

8.3.1 Control of SO_2 Emissions

The choice of a flue gas desulphurization (FGD) system depends on a variety of factors including cost, operating characteristics, ability to handle different qualities of coal, performance and waste by-products. Of the many types of FGD technologies, wet limestone scrubbers producing sludge waste were first generation systems. Initial refinements to FGD technology added an oxidation process which facilitates the production of gypsum, a by-product used in construction. Dry, semi-dry and regenerable processes represent yet another generation of FGD technologies.

8.3.2 Control of NO_x Emissions

Nitrogen oxides are formed during combustion by the combination at high temperatures of nitrogen and oxygen naturally found in the air and from fuel-bound nitrogen. In the case of coal and residual oil, most of the NO_x is derived from fuel nitrogen.[4] As NO_x production is dependent on combustion regimes, the range of NO_x emissions for a specific fuel is wide and difficult to characterize. For example, the level of NO_x emissions from the same fuel varies considerably by type of plant--cyclone, wall-fired units or tangential-fired boiler. In addition, design characteristics such as spacing of burners and fuel mixing also affect the rate of NO_x emissions.

The two main approaches to NO_x reduction are modification of the combustion process (by modifying the flame or adding a secondary combustion zone) or by reaction of the NO_x with ammonia. The reaction may take place by injecting ammonia into the ductwork, called selective non-catalytic reduction (SNCR), or in special plants after the boiler containing a catalyst to aid the reaction, termed selective catalytic reduction (SCR).

Several innovative clean coal technologies (that simultaneously achieve moderate to high removal rates for both sulphur dioxide and nitrogen oxides) are currently under development. These technologies include limestone injection multi-stage burners (LIMB), advanced slagging combustors, gas reburning coupled with in-duct sorbent injection (GR-SI), electron beam (E-beam), copper oxide, NOXSO and SULF-X. Demonstrations have shown SO_2 removal of 90 percent or more and NO_x removal of up to 80 percent. A fundamental advantage of such systems is a combined lower average cost compared to those for separate control systems with comparable levels of SO_2 and NO_x reductions. Furthermore, they may be designed to use less energy than conventional FGD, and unlike FGD do not produce large quantities of waste.[5]

As a result of growing regional concern over waste management, regenerable FGD processes are the object of increasing research and development. However, as regenerable systems tend to be more complex, less well-developed, and more costly, most FGD installed today continues to be of the wet lime/limestone process, producing either gypsum residue or saleable gypsum.[6]

8.3.3 The Canadian Setting

Proven technologies available to reduce SO_2 emissions from smelters, power plants and other sources have been applied or are expected to be implemented within a few years. By 1994, state-of-the-art technologies will be in place in Canadian non-ferrous smelters. Flue gas desulphurization scrubbers (wet limestone type) are planned at several electric power plants. In Ontario, between two and twelve coal-fired units will be retrofitted depending on load growth; while in New Brunswick, new coal-fired units with scrubbers are planned and one is now under construction at Belledune. For these scrubbers, commercial gypsum recovery is being investigated.

While these control technologies will play a significant role, particularly for existing plants, they impose an energy penalty and pose other environmental problems, such as sludge disposal and water contamination. In the longer term, new control technologies which permit simultaneous treatment of SO_2 and NO_x, such as the copper oxide process, may replace conventional scrubbers if current research and development (R&D) programs prove to be successful. However, the need to address issues such as SO_2 in conjunction with other environmental concerns such as NO_x and CO_2 means that in the long run, new, more energy-efficient production technologies will be required.[7]

Major advances in NO_x control technologies are in use in Japan, Germany and California. However, some of the most promising technologies require further research, development and demonstration for Canadian fuels under Canadian conditions.[8,9]

Of the various options for controlling emissions (pre-combustion, combustion and post-combustion), combustion technologies present the greatest opportunities for increases in thermal efficiency and net reductions in CO_2 and other radiative gas emissions.[10] Owing to the fact that coal-fired electrical plants are in the order of 35 percent energy efficient, every percentage improvement in efficiency has a leveraged impact on the reduction of emissions. Many of these advanced generation technologies also result in significantly improved methods of controlling SO_2 and NO_x emissions.

8.4 Advanced Generation Technologies

World-wide research by the electric power, chemical and coal industries has led to the development of a range of combustion technologies which mitigate the environmental impacts of burning coal for electric power generation. Of these new technologies, integrated gasification combined cycle (IGCC) promises the best combination of economic, efficiency and environmental benefits. It has been identified by many electric utilities as **the** coal-based power generation technology for the 1990s. Almost all the sulphur (99 percent) can be removed and produced in a saleable molten form and NO_x emissions are extremely low at around 25 percent of those emitted by conventional coal-fired plants. Low NO_x burners under development for gas turbines will lower NO_x emissions further.

Integrated gasification combined cycle offers a combination of advantages which **no** other coal-based system can match. IGCC provides short lead time construction, competitive capital cost, operational and planning flexibility, lower water consumption, small land requirements, and markedly reduced sulphur, nitrogen, particulate and CO_2 emissions relative to conventional coal-fired power plants. Ongoing progress in gas turbine technology signals further gains in IGCC efficiency.[11] System improvements stemming from IGCC demonstration projects currently being built, together with those resulting from current pilot-scale research, portend greater efficiency, lower costs and major reductions in CO_2 emissions.[12] Moreover, IGCC affords a **unique** opportunity for co-producing valuable chemical byproducts.

As a result of these benefits, interest in IGCC utility applications is growing world-wide. In California, Texaco plans to have a commercial plant producing electricity from a mixture of 75 percent coal and 25 percent sewage sludge from Los Angeles by 1992. Materials such as contaminated soils, waste oils, and refinery wastes can also be easily disposed of due to the higher temperatures at which gasifiers operate. The first commercial IGCC unit to come on-line in Europe is a 250-MW plant scheduled for completion in 1993 at Buggenum, Holland. Germany is also planning to have a 150-MW IGCC unit in commercial operation by 1994.

Within Canada, IGCC is under active investigation in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta. The Coal

Association of Canada (CAC) has proposed an IGCC demonstration project which would evaluate CO_2 removal and disposal options such as enhanced oil recovery.

8.4.1 Fuel Cells and Magnetohydrodynamics (MHD)

A fuel cell is a device in which hydrogen obtained by reforming natural gas, methanol or coal-derived gas reacts electrochemically with oxygen to generate electric power. The power generation efficiency of a fuel cell is high, some 40 to 60 percent, and these efficiency levels are maintained even under partial load operation. Waste heat recovery from fuel cell operations may yield total energy efficiencies of up to 85 percent where waste heat is used for domestic hot water, space heating, or low-level process heat for industrial uses.[13] Owing to their energy efficiency compared to conventional generating units, fuel cells offer a significant reduction in CO_2 emissions.

Fuel cells appear to be one of the most promising systems for power generation in the 21st century because of their high efficiency, environmental compatibility and fuel diversity. As these features are exhibited regardless of unit capacity, it is expected that fuel cells will find use in various applications, including dispersed on-site power plants, cogeneration systems, automobiles and portable generators, as well as centralized power stations. However, technical and economic problems such as reliability, operating performance and cost, must be resolved before commercial application of fuel cell systems becomes possible.[14]

Magnetohydrodynamics is a direct burning, high efficiency advanced fossil fuel technology for generating baseload electric power. While this technology holds considerable promise in terms of its efficiency and environmental performance, it is not expected to be commercially available for electric utilities until the turn of the century. It is anticipated that first generation MHD power plants will have efficiencies of 40 to 50 percent (scrubbers not required) and mature plant efficiencies of 60 percent.[15]

Magnetohydrodynamics is in the development stage--its maturity, potential applicability and economics have not been established and there are drawbacks which must be overcome before it is recognized as a viable supply option for electric power production. It is very capital intensive, requires superconductors that have only reached the laboratory stage of development, and the high temperature combustion could result in high nitrogen oxide emission rates.[16] Despite these drawbacks, MHD affords significant potential for high efficiency and low emissions for electric power utilities beyond the turn of the century.

8.5 Electric Power Technologies, Strategies and Emissions

To evaluate all technologies within a consistent framework, a planning model (ELGEM) jointly developed by the Canadian Energy Research Institute and the Alberta Research Council was modified to account for new costing information and emissions data.[17] In Version 2.0, the costs of electric generating technologies (e.g., atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC) and IGCC) and their air emission factors have been added using the most recent data from the Canadian electric utilities, the Canadian Electrical Association (CEA), the Electric Power Research Institute (EPRI), and the technology developers.

Other improvements made to ELGEM include the incorporation of emission control technologies into the modelling framework. This enhancement allows ELGEM to assess how emission control policies in Canada would impact on the electric power sector. Currently three levels of emission control ranging from 30 to 80 percent reductions for each of NO_x and SO_2 have been incorporated, reflecting a range of cost and technology options. These technologies include low excess air, overfire air, low NO_x burner, selective catalytic reduction, flue gas desulphurization, gas reburn and sorbent injection. Only generic technology costs have been considered; however, these costs may vary for specific retrofit applications at some plant locations. Carbon dioxide is not controlled in this version, as there are no economically viable options for reducing post-combustion CO_2 emissions. However, regional CO_2 emissions in Canada are reported for each scenario to assess the emissions impact of changes in energy efficiency under the various scenarios (see Appendix C for a more complete description of the ELGEM modelling framework and Appendix D for regional model results of the various scenarios presented below).

The ELGEM model was used to assess the cost of Canadian electric power and regional emissions impact for SO_2, NO_x and CO_2 under six different cases:

(1) Reference case: existing SO_2 controls only, as contained in Canada's Acid Rain Control program;

(2) Base case: existing SO_2 controls plus suggested NO_x target reductions;

(3) Demand-side management/Conservation case: electricity demand reduced by 20 percent from base case levels by 2009;

(4) Coal technology costs: 15 percent reduction in the installed capital cost of IGCC, PFBC and AFBC relative to base case levels;

(5) Coal technology efficiency gain: 10 percent (absolute) gain in energy efficiency for IGCC, PFBC and AFBC relative to base case efficiencies assumed to occur over the 1990 to 2010 period; and

(6) No nuclear constraints: no moratorium on nuclear power development in Ontario.

In order to account for the net impact of changes in NO_x regulations and the impact of those regulations on the cost of Canadian electric power generation, the reference case was first subtracted from the SO_2/NO_x (base) case. In order to meet suggested reductions in NO_x emissions, the present-value cost of Canada-wide electricity generation would rise by $2.98 billion over the 1988-2011 period. This translates to a cost of $1443 per tonne for acid gas removal.

As the implementation of NO_x controls similar to those suggested in the recent NO_x/VOC Draft Management Plan seemed imminent, this scenario (SO_2/NO_x case) is used as the base case for comparison of the remaining scenarios evaluated in ELGEM. Again, to show the net impact on the present-value cost of Canadian electric power generation and the resulting reduction in Canada-wide SO_2, NO_x and CO_2 emissions, the SO_2/NO_x case is subtracted from each of these scenarios. Summary results depicting these net impacts are displayed in Table 8.1.

As shown in this table, demand-side programs are the most cost-effective means of making a major reduction in total emissions. Relative to the base case, savings in the present value cost of Canadian electric power generation total $166 billion; cumulative emissions are down by 803 Mt for the 1988-2011 period relative to the base case. While the ELGEM model does not currently account for DSM/Conservation supply curves, the model was used to infer an opportunity cost for emissions reduction. Using the savings in

TABLE 8.1

SUMMARY RESULTS
INCREMENTAL COST AND EMISSIONS SAVINGS[a]

Scenario	CO_2 (Mt/yr)	SO_2 (Mt/yr)	NO_x (Mt/yr)	Total (Mt/yr)	Change in Objective Function (million $1989 Cdn)	Hurdle Price[b] ($1989 Cdn/tonne)
DSM/Conservation	799.8	1.8	1.0	802.6	166,501	207.45
Lower Capital Cost	9.0	0.9	0.6	10.6	903	85.22
Higher Coal Efficiency	124.5	0.8	0.6	126.0	1,482	11.76
No Nuclear Constraints	180.9	(0.4)	(0.03)	180.5	1,765	9.78

SOURCE: Canadian Energy Research Institute.

[a] Net reduction in emissions and present value costs relative to the base case scenario.

[b] The hurdle price can be interpreted as the **maximum** dollar per tonne expenditure which can be justified in achieving the targetted reductions in emissions, under the various scenarios.

emissions and cost of power, these results suggest that demand-side programs costing less than $207.45 per tonne should be cost effective for Canada as a whole.

Unconstrained development of nuclear power follows, with savings relative to base case levels of $1.8 billion and associated emissions reductions of 180 Mt for the 1988-2011 period. Improving the energy efficiency of clean coal technologies, such as IGCC and PFBC, follows closely with savings in the cost of Canadian power of $1.5 billion and emissions savings of 126 Mt over the 1988-2011 period. Reducing the capital cost of new coal technologies follows with savings in Canadian electric power of $0.9 billion, but emissions for the 1988-2011 period fall only 11 Mt.

While these results support popular assessments undertaken to date, it is important to note that the ELGEM results presented above assume that a tonne of NO_x, SO_2 or CO_2 is equally harmful to the environment. However, given that CO_2 accounts for over 99 percent of total emissions from Canadian electric power production, these results could more accurately be thought of as representative costs to reduce CO_2 emissions from Canadian electric power production.

While it is exceedingly difficult to assess the relative impact of SO_2, NO_x and CO_2 emissions on the environment and the economy, such a comparison is important for the determination of the funds to be assigned and for the design of programs to be undertaken to reduce emissions. For example, if we could support the position that a tonne of CO_2 was only 1/15 as harmful to the environment as acid rain, then increasing the efficiency of IGCC and the nuclear power option are equal in terms of their relative costs and emissions reduction potential. Reducing this CO_2 ratio further results in IGCC being more cost effective than nuclear power. It is interesting to note that, even at this 1/15 ratio, CO_2 emissions still comprise over 85 percent of total emissions from Canadian electric power production.

All technologies--DSM, clean coal technologies and nuclear power--will play a part in reducing atmospheric emissions from Canadian electricity production. While DSM/conservation programs have the most dramatic impact, the question of cost and deliverability bear important consideration. Fortunately, the implementation of DSM/conservation programs is starting to take place in Canada.

These actions will help to determine the most cost-effective demand-side programs together with the most effective mix of complimentary technologies--hydro, nuclear and fossil-fuelled.

8.6 Recommendations

- Research and development of clean coal technologies for use in Canadian electric power production should be increased and export of Canadian-based, clean coal technology to developing countries should be evaluated.

- Electric utilities should be allowed to include demand-side programs and competitive bidding programs into utility rate base.

- Public Utilities Boards' regulatory powers should be changed to recognize energy efficiency in electricity production and use, not simply rates and rate structures.

- Government should undertake quality analyses of the impacts and costs of new regulations to ensure that such new regulatory requirements do not put Canadian industry and services at a comparative disadvantage in the world economy.

- Canadian public and government spokesmen must recognize the strategic importance of coal to fuelling the electric power needs of Canadian business, industry and residences. Coal constitutes over 80 percent of Canada's remaining fossil fuel reserves; coal can be used cleanly; and the price of coal is directly tied to the cost of production not to geopolitical events. Both changes in regulatory practices and new clean coal technologies will be required to ensure that coal benefits Canadian society without causing detrimental impacts to the environment.

- Significantly more R&D funding support should go to research, development and demonstration of integrated energy efficiency programs which include burnable waste for energy.

- Given the considerable importance of Canada's municipal governments to planning for atmospheric emission reductions, these organizations should be more actively involved in Canadian energy/environmental policy and policy initiatives.

- The use of IGCC burning coal and sewage sludge, akin to plans for the Cool Water Plant, should be seriously evaluated by Canadian energy/environment policy makers--an integrated approach to energy and environment is mandatory.

- Research and demonstration of fuel cells by Canadian businesses and industry should be actively supported.

Footnotes

[1] K. Morgan MacRae, *Critical Issues in Electric Power Planning in the 1990s* CERI Study No. 33, (Calgary, Alberta: Canadian Energy Research Institute, November 1989).

[2] International Energy Agency, *Emission Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1988), p. 58.

[3] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," Vol. II - Emissions and Controls (Washington, D.C.: National Acid Precipitation Assessment Program, 1987) p. 2-6.

[4] United States, Environmental Protection Agency, *Policy Options for Stabilizing Global Climate* (Washington, D.C.: EPA, February 22, 1989), p. VII-132.

[5] Ibid., p. 68.

[6] International Energy Agency, *Emission Controls in Electricity Generation and Industry*, 1989, p. 68.

[7] Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls (Draft)* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-42.

[8] Environment Canada, *Control Technologies for Management of Nitrogen Oxides* (NO_x) *and Volatile Organic Compounds (VOC) in Canada:* Work Sub-Group 6.2 Report, Stationary Sources - NO_x, (Ottawa, Ontario: Environment Canada, January 1990) p. 27.

[9] Ontario Hydro, *Thermal Cost Review* (Toronto, Ontario: Ontario Hydro, October 1989) pp. 35-36.

[10] Coal Association of Canada, *Brief on Global Warming to House of Commons Standing Committee on Environment* (Calgary, Alberta: Coal Association of Canada, December 14, 1989).

[11] For information on recent advances in gas turbine technology, see California Energy Commission, *Chemically Recuperated Gas Turbine - Staff Report Draft* (Sacramento, California: California Energy Commission, January 1990) and Robert H. Williams and Eric D. Lawson, "Aeroderivative Turbines for Stationary Power," *Annual Review of Energy 1988*, (Palo Alto, California: Annual Reviews, Inc., 1988) pp. 429-489.

[12] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-43.

[13] United States, U.S. Congress Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects*

for the 1990s, OTA-E-246 (Washington, D.C.: United States Government Printing Office, July 1985), p. 103.

[14] T. Sugimoto, "Prospects for the Future for the Development of Solar Cell, Fuel Cell Systems, Advanced Batteries and Electric Energy" in *EPRI Proceedings 1989 Conference on Technologies for Producing Electricity in the Twenty First Century*, San Francisco, California, October 20-November 2, 1989, p. 5

[15] Ibid.

[16] United States, Environmental Protection Agency, *Policy Options for Stabilizing Global Climate*, 1989, p. VII-134.

[17] The ELGEM model is a linear programming model of electricity generation for Canada. Version 1.0 of ELGEM was developed by the Alberta Research Council and the Canadian Energy Research Institute to assess the potential savings of greater electricity trade within Canada and between Canada and the United States. The results of these analyses were presented in CERI Study No. 33--*Critical Issues in Electric Power Planning in the 1990s* published by the Institute in November 1989.

APPENDIX A

EMISSION CONTROL TECHNOLOGIES

Appendix A

EMISSION CONTROL TECHNOLOGIES

A.1 Introduction

Technologies for the control of emissions from coal combustion have developed considerably over the last decade with improvements in coal-cleaning processes, in the fuel combustion process itself, and in the cleaning of exhaust gases after combustion. The term clean coal technologies is commonly used to refer to this set of new systems and controls that produce fewer air pollutants than conventional combustion methods. As carbon dioxide (CO_2) has only recently become of interest, technological developments have largely focussed on control of particulates, sulphur dioxide (SO_2) and nitrogen oxide (NO_x).

Control of pollutants released in the combustion of coal can be achieved in several ways:[1]

- Particulate emissions can be effectively captured after combustion by use of electrostatic precipitators and bag filter systems.
- Sulphur dioxide emissions can be reduced prior to combustion by switching to low-sulphur fuels or by removing sulphur from the coal (e.g., by coal washing or coal gasification); during combustion; or after combustion by treating the flue gas.
- Nitrogen oxide emissions can also be reduced by combustion modification techniques or following combustion by flue gas treatment devices.

In addition to particulates, SO_2, and NO_x, solid and liquid by-products or wastes are also formed during combustion and in the control of emissions. For example, the waste produced in the desulphurization of flue gases has become a subject of regulation, particularly where adequate space for waste disposal is problematic. In many cases, regulations promulgated to control waste by-products will limit the choice of available control technology options available and ultimately influence the costs of emissions control.

Table A.1 summarizes the control technologies for SO_2 and NO_x, including their commercial status and SO_2/NO_x reduction effectiveness.

A.2 Particulates Control

Fly ash, formed when the mineral matter in coal is converted to ash, is largely responsible for particulate emissions from coal burning plants. Particulates control technology is now standard equipment on both old and new coal-fired facilities. There are two standard control methods for utility systems, electrostatic precipitators (ESP) and baghouse fabric filters, which can provide reductions of over 99 percent in particulate emissions. The selection of technology depends on the sulphur content of the coal, sulphur emissions control equipment and fly ash composition. Since the 1920s, ESPs have been the preferred technology for particulates control as they are less expensive to install and operate than baghouse filters. Recently, however, attention has turned to greater particulates control and calls for increased use of the more efficient baghouse filters due to concerns that smaller particulates can also cause health problems.[2]

A.3 Sulphur Dioxide Control

There are two types of sulphur in coal--pyritic and organic sulphur. Pyritic sulphur is found in coal as small particles of iron pyrite. Pyritic sulphur can be removed through a flotation or other hydro-based process, generally known as physical cleaning. Organic sulphur is chemically bonded to the coal. It appears that this type of sulphur can be removed through chemical or biological cleaning processes, although the effectiveness of organic sulphur removal is still unclear. Each form can comprise 30 to 70 percent of the total sulphur content, depending on the coal type.

The discussion of ways to control SO_2 emissions commonly centers on pre-combustion, combustion and post-combustion control technologies.

A.3.1 Pre-Combustion

Pre-combustion control methods generally refer to the physical cleaning of coal.

The only coal cleaning techniques commercially available today are physical techniques designed to remove mineral matter such as pyritic sulphur and ash. These physical separation methods take advantage of the fact that the carbonaceous portion of coal is lighter

TABLE A.1

POWER PLANT CONTROL TECHNOLOGY FOR SULPHUR AND NITROGEN OXIDES

Technology	Commercial Status	Application/Waste	SO_2 and NO_x Reduction[a]
Pre-Combustion			
Physical Coal Cleaning	Commercial		10-30% SO_2[b]
Advanced Coal Cleaning	R&D		90% SO_2[b]
Coal-Water Fuels	R&D, Small Industrial Scale		50% pyritic SO_2 and some NO_x
Combustion Control			
Combustion Modification/ Low-NO_x Burners	Commercial as well as R&D	Retrofit and New	30-50% NO_x
Advanced Low-NO_x Burners	R&D		Up to 70% NO_x
Off-Stoichiometric Control	Commercial	New	30% NO_x
Catalytic Combustion	Initial Testing	Retrofit	80% NO_x
Furnace Sorbent Injection	Demonstration	Retrofit: Waste May be Hazardous	60-75% SO_2
Post-Combustion			
FGD-Wet Lime and Limestone	Commercial	New and Retrofit; Gypsum or Wet By-product	90% or more SO_2
Spray-dryer FGD Lime	Commercial	New and Retrofit; Dry By-product	70-80% SO_2
Regenerable FGD	Commercial	New; Limited Quantities of Waste	90% SO_2
Combined de-SO_2/de-NO_x FGD	Demonstration	Small Quantities of Waste; New and Retrofit	90% SO_2/80% NO_x
Selective Catalytic Reduction	Commercial	Industrial and Utility; New and Retrofit	80-90% NO_x
Selective Non-Catalytic Reduction	Commercial	Compact and Easy to Install; Waste May be Considered Hazardous	30-50% NO_x
Dry Injection of Sorbents	R&D and Demonstrated		N.A.

SOURCE: International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1989), p. 59.

[a] Values indicated here are only indicative. Technologies are under development and experience with demonstration plants may differ and may also vary with coal qualities. For example, Denmark's experience with FGD technology suggests that wet lime and limestone SO_2 reductions of 93 percent can be attained, while for Selective Non-Catalytic Reduction, NO_x reductions of not more than 60 percent are expected.

[b] Depending on differences between pyritic and organic sulphur content across various types of coals.

than the mineral matter and can be separated by flotation.[3] Organic sulphur, which is a chemical constituent of coal, cannot be removed by existing conventional, gravity-based cleaning processes. Moreover, none of these coal preparation techniques removes nitrogen from the coal or affects the production of nitrogen oxides.

Traditionally, coal cleaning was undertaken primarily to remove ash and reduce boiler operational problems such as slagging, fouling and corrosion. It also increases the specific energy content of the coal and reduces transportation costs. Recently, coal cleaning has become more widely recognized as a limited but relatively economic sulphur reduction technique for combustion applications.

Current coal cleaning processes typically involve the use of jigs, dense media vessels, concentrating tables, cyclones and froth flotation units. High efficiency processes would incorporate all of this equipment, whereas lower levels of cleaning would utilize only some of the components. The sulphur removal efficiency attainable by current physical coal cleaning technology is strongly dependent on the portion and particle size distribution of pyritic sulphur contained in a coal. While a maximum sulphur removal efficiency of 50 percent using present techniques is often cited, most facilities operate in the 10 to 30 percent range. As removal efficiency increases above 30 percent, costs rise rapidly due to the large amounts of coal rejected with the sulphurous product discard.[4]

A.3.1.1 Advanced Processes

Several advanced coal cleaning techniques are under development that may in the long term yield significant reductions in sulphur emissions. These processes are classified as advanced physical or chemical-biological processes.

The advanced physical processes utilize the differences among coal, pyrite and ash forming mineral particles, with respect to their specific gravity, electrical characteristics, affinity for water and magnetic characteristics. The leading physical cleaning generic processes being tested or demonstrated include: oil agglomeration; micro bubble flotation; column flotation, true heavy media bath, true heavy media cycloning; electrostatic separation and magnetic separation. Test results suggest that several of these processes are capable of removing 60 to 90 percent of the pyritic sulphur and similar quantities of the ash forming minerals at acceptable process and product loss costs.[5]

To go beyond what can be achieved with physical separation methods, the organically bonded sulphur must be separated from the coal. The commercial prospects for this aspect of coal cleaning are being explored through basic research efforts in two areas--chemical and microbial cleaning. Chemical cleaning is at the proof-of-concept stage while microbial cleaning is at benchscale. Chemical cleaning, which has the potential to remove over 90 percent of total sulphur and ash, involves treating the coal with chemicals or solvent refining under high temperature and pressure. Microbial coal cleaning is an experimental technique in which certain types of fungus and bacteria absorb the sulphur.[6] Although most of the sulphur can be eliminated in these latter processes, costs are expected to be substantially higher than the costs of either conventional or innovative physical coal cleaning.[7]

A.3.1.2 Other Options

Other techniques for reducing the sulphur content of coal used in the generation of electricity include: coal switching, coal gasification, coal liquefaction and coal-oil co-processing.

Switching to low-sulphur coal may be cost effective, however, there are constraints to using low-sulphur coal in utility boilers originally designed to burn coal of a higher sulphur content. Upgrading of particulate control devices may be required and coal handling equipment may also require upgrading to compensate for the greater quantities of lower heat content coal required to generate an equivalent amount of electricity. These factors add to the cost of generating electricity and may lead to derating of the boiler.[8]

Other pre-combustion processes also offer the possibility of using coal more cleanly. For example, the development of gasification processes to produce fuel gas for the combined cycle generation of electricity (IGCC) is a case where considerable research and demonstration activity is ongoing. Coal liquefaction and coal-oil co-processing remain longer-term options which result in cleaner use of coal but which are targeted primarily at the transportation sector, not electricity generation, and are not therefore considered further in this report.[9]

A.3.2 Combustion Control

In the past, the principal means of SO_2 control was through a post-combustion process known as flue gas desulphurization (FGD is described in Section A.3.3). The use of wet or dry FGD scrubbers requires costly and complex apparatus entailing heavy maintenance costs. To provide an alternative cheaper method, considerable effort in Germany, Canada and the U.S. has gone into development of simple systems for injecting powdered lime or limestone, either dry or in the form of water slurries, into the upper region of the furnace to react with the SO_2 directly. However, many of these combustion control technologies are still at the research and demonstration stage.

These emerging technologies are designed to capture SO_2 before it exits the combustion chamber, or in the ductwork downstream from the combustion zone. The combustion chamber technique is referred to as furnace sorbent injection, while the post-combustion method is termed low-temperature sorbent injection.[10]

A.3.2.1 Furnace Sorbent Injection (FSI)

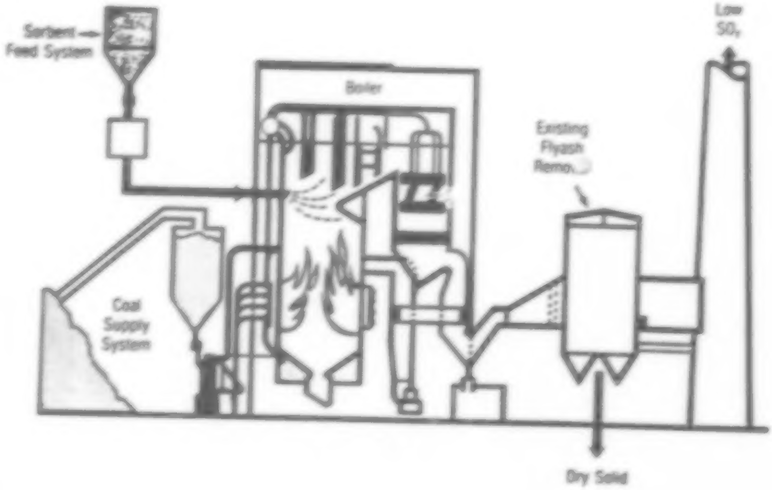
Furnace sorbent injection is based on the injection of pulverized calcium-based sorbent materials, such as limestone or calcium hydroxide, directly into the furnace cavity of a coal-fired boiler (see Figure A.1). When exposed to furnace temperatures, the sorbent rapidly decomposes to form reactive lime particles that capture SO_2 in suspension. This results in the formation of calcium sulphate particles. The flue gases carry this calcium sulphate, along with any unreacted lime, out of the furnace where a conventional particulate control device collects them with the fly ash.

In-furnace SO_2 capture is a chemical and physical process that is influenced by a number of factors, including sorbent properties, boiler temperatures and residence times, sorbent mixing and dispersion within the furnace, and coal composition. Optimal SO_2 removal is based on the interplay of all of these factors. Sulphur dioxide removal rates vary considerably but generally are from 30 to 50 percent in optimum conditions.[11]

Use of FSI often requires upgrading of the particulate control devices to maintain particulate emission standards. Furnace sorbent injection produces a dry powder waste which may be considered suitable for landfill. In Germany, however, this waste has recently been classified as "hazardous", severely restricting its potential disposal options and raising costs.[12]

For some low-sulphur coals, or situations not requiring high degrees of SO_2 removal, these direct injection methods provide adequate SO_2 reduction though they are generally chemically inefficient, in as much as they need substantial excess quantities of sorbent

Figure A.1
Sorbent Injection


Sorbent
Feed System
Boiler
Existing
Flyash
Remo...
Low
SO_2
Coal
Supply
System
Dry Solid

SOURCE: Alberta Department of Energy, *Development of Clean Coal Technologies for Alberta.*

to achieve these reductions. As a consequence, they result in greater complexity of burners and furnaces and additional cost in disposing of excessive amounts of waste material.[13]

In-furnace limestone or sorbent injection technology is on the verge of commercialization, but it has not attracted much attention because it can only meet current Canadian guidelines on plants firing very low-sulphur coal, and cannot meet New Source Performance Standards in the United States. Sorbent injection can be cost effective only when moderate SO_2 capture is required.[14] For example, Saskatchewan Power will use sorbent injection for their new Shand generating project.

A.3.2.2 Low-Temperature Sorbent Injection

In a variation of the injection process, termed low-temperature sorbent injection, dry or slurried sorbents are injected into the post-boiler duct. These sorbents include: dry sodium compounds, powdered lime hydrates in conjunction with water or steam, and lime slurries. Potential advantages of these processes include simplicity, low capital cost of sorbent preparation and injection equipment, and adaptability to retrofit applications.[15]

Uncertainties in the process include: applicability to boilers firing high-sulphur coals; sorbent utilization rates; potential for sorbent caking in the duct and particulate control systems; and disposal of solid wastes containing unreacted lime. This technique appears to be a very low capital cost approach to partial removal (50 to 70 percent) of SO_2. Because of its low cost, low-temperature sorbent injection is especially attractive for retrofit on older boilers with relatively low capacity factors and for use in developing countries.[16]

A.3.3 Post-Combustion

Flue gas desulphurization is the only currently available method for removing a high portion of the sulphur oxides produced during coal combustion. Flue gas desulphurization refers to sulphur control processes that are fitted to the back end of the combustion process at the point of flue gas emission. In general, FGD systems use sorbents--alkaline materials such as limestone--to absorb and remove the sulphur dioxide from the flue gas. Flue gas desulphurization processes tend to be very large and expensive, since large volumes of flue gas containing very low concentrations of SO_2 must be treated. Large quantities of waste product result from the reaction of the sulphur dioxide and the sorbent.[17]

The choice of a FGD system depends on a variety of factors including cost, operating characteristics, ability to handle different qualities of coal, performance and waste by-product. The types of FGD systems currently in operation are described in Table A.2. Also shown are the variety of sorbents and end-products produced by each system.

Of the many types of FGD technologies (see Table A.3), wet limestone scrubbers producing sludge waste were first generation systems. Initial refinements to FGD technology added an oxidation process which facilitates the production of gypsum, a saleable by-product. The addition of forced oxidation is now part of most new wet FGD systems. Dry, semi-dry and regenerable processes represent yet another generation of FGD technologies.

Wet FGD refers to a process where SO_2 is reduced through a chemical reaction of sulphur with alkaline sorbents sprayed into the flue gas. To maximize contact between the gas and the liquid, this is usually done in a spray tower. SO_2 reduction of 90 percent or more is common with wet scrubbers. Disadvantages of wet scrubbers include their large space requirements, relatively high retrofit costs and high volumes of waste by-product (mostly gypsum) that adds to existing waste disposal problems associated with the ash from coal combustion. In addition, there is a significant energy penalty in using FGD--energy consumption of wet systems averages about 4 percent but estimates as high as 8 percent have been cited.[18] The decrease in efficiency owing to FGD controls also leads to somewhat higher per unit CO_2 emissions.

There are two commercial versions of this control technology that relate to by-product recovery: non-regenerable (throwaway) and regenerable (those that produce sulphur, sulphuric acid and other recoverable by-products). As shown in Table A.3, most FGD systems in place are non-regenerable, with wet scrubbing systems using aqueous slurries of lime or limestone as a sorbent. By the end of 1988, there were 67 000 MW of capacity equipped with scrubbers and 5000 MW under construction in the United States. Over half the installed capacity and the longest operating experience is with the wet limestone slurry process (see Table A.4).

Throwaway FGD systems applied to high-sulphur coal produce either a fixated sludge or gypsum. Regenerable systems, when applied to a high-sulphur coal-fired boiler, produce a by-product

TABLE A.2

TYPES OF FGD SYSTEMS CURRENTLY IN OPERATION

System	Sorbent	End Product
Non-regenerable Systems		
Wet Scrubbers	Lime/Limestone Lime/Fly Ash	Gypsum or Calcium Sulphite/Sulphate Calcium Sulphite/Sulphate/Fly Ash
Spray-Dry Scrubbing	Lime	Calcium Sulphite/Sulphate/Fly Ash
Seawater	Primary: Seawater Secondary: Lime	Waste Seawater
Walther	Ammonia	Ammonium Sulphate
Regenerable Systems		
Dual Alkali	Primary: Sodium Hydroxide Secondary: Lime/Limestone	Calcium Sulphite/Sulphate
Bergbau-Forschung/Uhde	Activated Carbon	Concentrated SO_2
Wellman-Lord	Sodium Sulphite	Concentrated SO_2
Linde-SOLINOX	Physical Absorption	Concentrated SO_2
Spray Dry Scrubbing	Sodium Carbonate	Elemental Sulphur
MgO-Process	Magnesium Oxide	Concentrated SO_2
Electron Beam	Lime Ammonia	Ammonium Sulphate and Ammonium Nitrate

SOURCE: International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1989), p. 62.

TABLE A.3

TYPES OF FGD SYSTEMS IN USE OR PLANNED[a] (selected OECD countries)

FGD System	Total Number	Total GW
Wet Scrubbers		
Waste	164	66.3
Gypsum	141	58.5
Spray Dry Scrubbers	68	13.3
Sorbent Injection	12	1.3
Dual Alkali	9	3.8
Activated Carbon	1	0.3
Wellman-Lord	13	3.3
Magnesium Oxide	3	0.7
Planned--not selected	17	15.0
TOTAL	428	162.5

SOURCE: International Energy Agency, *Emissions Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1989), p. 64.

[a] Coal-fired systems only in the following countries: Austria, Denmark, Finland, Germany, the Netherlands, Italy, Japan, Sweden, the United Kingdom, and the United States.

TABLE A.4

UNITED STATES SCRUBBER EXPERIENCE 1988

Process	Capacity Installed or Under Construction MW	Percent	Operating Years
Limestone Slurry	37 766	53	16
Lime/Spray Drying	6 624	9	9
Dual Alkali	2 228	3	10
Other	25 382	35	
TOTAL	72 000	100	

SOURCE: Ontario Hydro, *Thermal Cost Review: Background Report* (Toronto, Ontario: October 1989), p. 62.

while regenerating the absorbing reagent. The choice among these systems often depends on regulatory requirements pertaining to waste disposal and the production of saleable by-products. Regenerable FGD technologies afford low waste production, however, they tend to be more complicated and costly than the "throwaway" by-product processes and have not, as a result, seen wide application. This situation may change in favour of regenerable processes, however, as increasing concern builds over the disposal of FGD waste.[19]

One means of reducing problems associated with solid waste disposal problems is reliance on FGD systems that produce a saleable by-product. For example, several utilities are currently relying on forced-oxidation FGD which injects compressed air into the scrubbing products and creates gypsum. Gypsum disposal is generally easier and less costly than typical FGD waste (requires 40 percent less acreage for disposal because of ease to dewater) and with upgrading can result in a commercially saleable product for the cement and wall-board industries.[20,21]

A.3.3.1 Processes Under Consideration in Canada

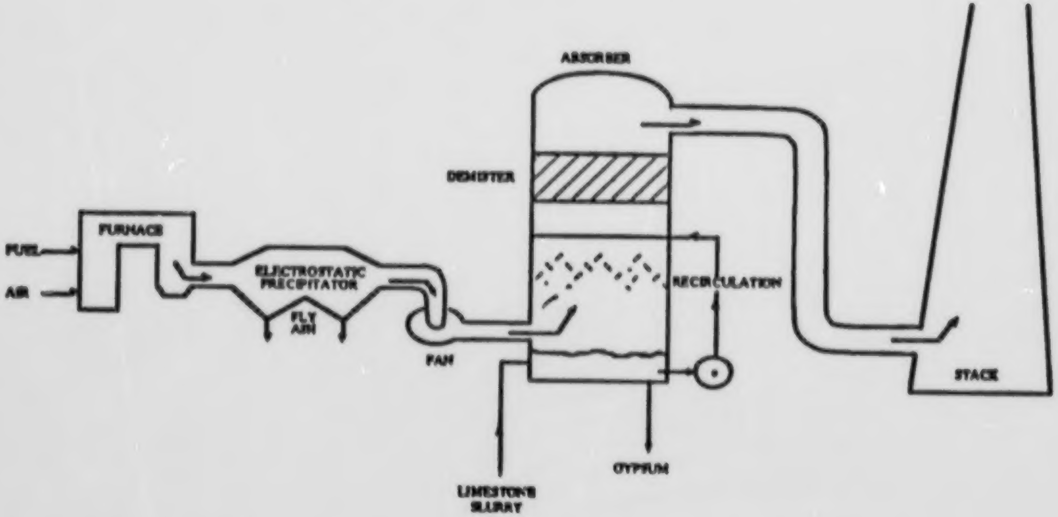
Ontario Hydro is considering both spray dry and dual alkali scrubbers for new units and limestone slurry scrubbers for the retrofit of some existing units and FGD is to be fitted to a plant under construction by New Brunswick Power.[22]

Wet Limestone Slurry Process

In this process (see Figure A.2), flue gas leaving the furnace is first cleansed of the fine ash carried in the gas by electrostatic precipitators. Flue gas then enters the absorber and is cooled by a spray of recirculating slurry which contains lime or limestone.

Flue gas, with the SO_2 removed, passes through a demister to remove entrained liquid droplets and is then directed to a stack designed to handle wet flue gas. Slurry streams are removed from the absorbers and dewatered to produce gypsum which can either be treated to produce a wallboard-quality gypsum or disposed of as landfill. Great care must be taken in the preparation of the landfill sites to avoid contamination of the adjacent groundwater.

Figure A.2
Limestone Slurry Process


ABSORBER
DEMISTER
FURNACE
FUEL
AIR
ELECTROSTATIC PRECIPITATOR
FLY ASH
FAN
RECIRCULATION
STACK
LIMESTONE SLURRY
GYPSUM

SOURCE: Ontario Hydro, *Thermal Cost Review*, Background Report, October 1989, p. 30.

Long-term average removal efficiency is 90 percent over a forty-year equipment service life. However, the highly corrosive operating conditions require expensive linings which must be repaired or replaced every eight to ten years.

Both Ontario Hydro and New Brunswick Power are planning wet limestone systems for their plants and are also actively investigating the recovery of gypsum as a saleable by-product.[23]

Dry Scrubbing Process

The dry scrubbing process was developed in an effort to solve many of the problems associated with wet scrubbers (see Figure A.3). In a dry scrubber, or spray dryer, the reagent slurry (lime) is injected into an absorber vessel in a finely atomized form. The droplets evaporate in the hot gas, leaving only dry, reacted particles for collection in a conventional baghouse or electrostatic precipitator.

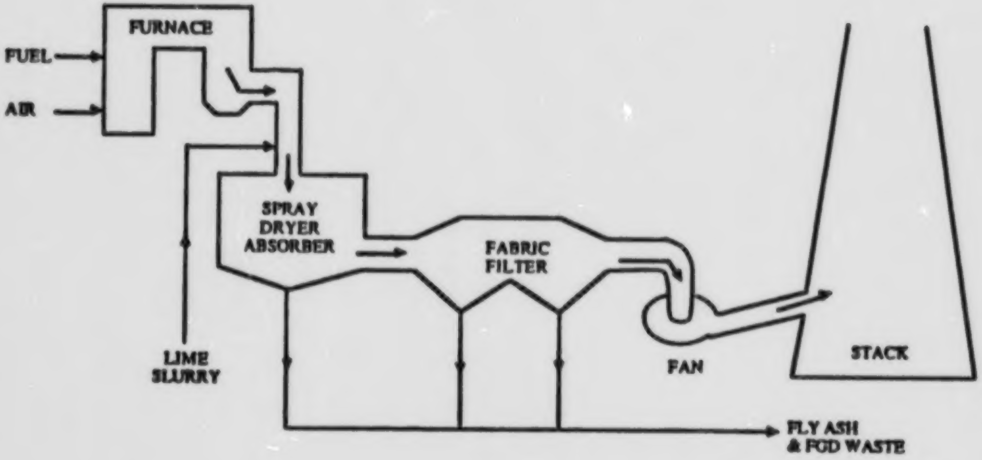
This process offers several advantages over wet lime/limestone SO_2 control processes--low energy consumption, low capital cost, high reliability, reduced corrosion of equipment and production of a dry waste product that is easily handled and disposed of. In addition, capital and operating costs are claimed to be up to 30 percent less than wet processes. Although considered commercially available for use on low-sulphur coal, uncertainties regarding the performance and economics of such systems to control SO_2 remain, as dry scrubbers have not been demonstrated on a full-scale utility system for high-sulphur coal boilers.[24]

Limestone Dual Alkali Process

A disadvantage of most wet scrubbing systems is the tendency to form scales on the internal surfaces of the equipment from precipitation of calcium compounds. This scaling can seriously interfere with the scrubbing operation, and may require excessive maintenance. To avoid this, dual alkali scrubbers use solutions based on sodium as hydroxide or sulphite, and remove SO_2 from the gas forming other sodium compounds in the scrubber. These are removed from the scrubber and regenerated by slaked lime and limestone to reform the scrubbing solution. The end-product is either gypsum or waste calcium sulphate for landfill.[25]

In this process (see Figure A.4), flue gas leaving the furnace is first cleaned of fine ash by an ESP. The flue gas then enters the

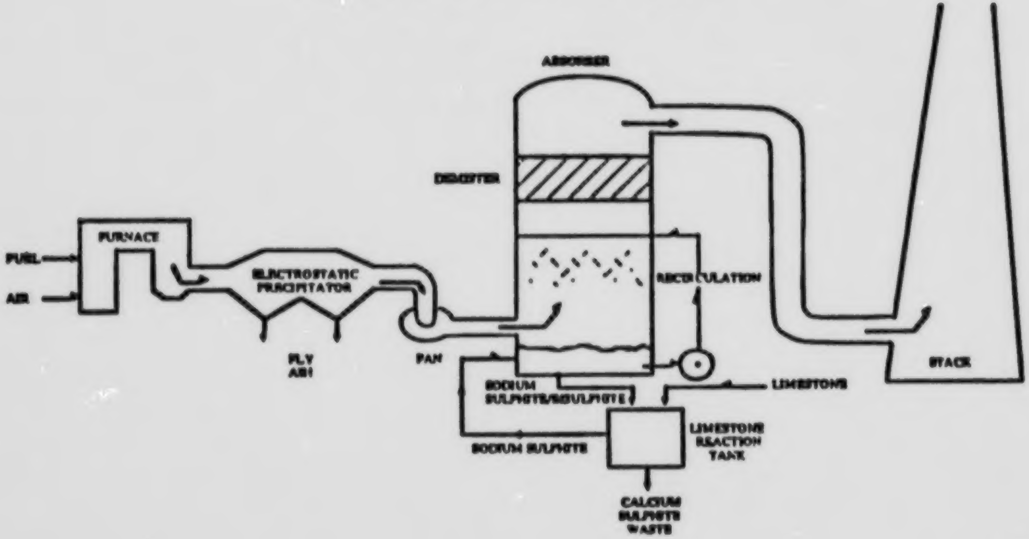
Figure A.3
Lime Spray Dryer Process


FURNACE
FUEL
AIR
LIME SLURRY
SPRAY DRYER ABSORBER
FABRIC FILTER
FAN
STACK
FLY ASH & FGD WASTE

SOURCE: Ontario Hydro, *Thermal Cost Review*, Background Report, October 1989, p. 33.

Figure A.4

Limestone Dual Alkali Process


ABSORBER
DEMISTER
FURNACE
FUEL
AIR
ELECTROSTATIC PRECIPITATOR
FLY ASH
FAN
RECIRCULATION
STACK
SODIUM SULPHITE/BISULPHITE
LIMESTONE
LIMESTONE REACTION TANK
SODIUM SULPHITE
CALCIUM SULPHITE WASTE

SOURCE: Ontario Hydro, *Thermal Cost Review*, Background Report, October 1989, p. 31.

absorber where it is contacted and cooled by a recirculating reagent consisting of a mixture of sodium sulphite and sodium bisulphite. A stream of the sodium sulphite/bisulphite reagent is taken from the absorbers to the limestone reaction tank to regenerate sodium sulphite which is returned to the absorber. The limestone reacts with the sodium bisulphite solution and produces a solid calcium sulphite waste. The calcium sulphite can be further treated to produce a wallboard quality gypsum or mixed with fly ash and used as landfill.

In comparison to the wet limestone slurry process, the greater reactivity of the sodium sulphite reagent allows higher removal efficiency--about 93 percent. In addition, a forty-year service life is easier to achieve than with the wet limestone slurry scrubber due to the less acidic conditions which exist in the alkaline scrubber.

In North America about 2000 MW, or 3 percent of total FGD capacity, is equipped with the dual alkali process, although lime rather than inexpensive limestone is used. Ontario Hydro plans to retrofit a limestone dual alkali process at its coal-fired Nanticoke plant.[26]

Union Carbide CANSOLV Process

Union Carbide together with the Federal government and an Alberta Crown Corporation (AOSTRA) have joined Suncor Inc. in funding a 2 MW pilot plant that will use innovative new technology to capture SO_2 at Suncor's Fort McMurray, Alberta integrated mined oil sands plant. The technology, called CANSOLV, was developed by Union Carbide and is claimed to recover 98 percent of SO_2 more efficiently and at lower cost than conventional systems. The key to the technology is an organic sorbent that reacts quickly with SO_2 and which is recycled in the process after the SO_2 has been recovered from it. CANSOLV is designed for use in virtually any large SO_2 emitting plant, including coal-fired and oil-fired generating stations, metallurgical smelters and industrial boilers. While expectations for the technology seem promising, it is still too early for reliable cost information to be available.[27]

A.4 Control of NO_x Emissions

Unlike the production of SO_2, nitrogen oxide emissions are not as directly related to the characteristics of the combustion fuel. Nitrogen oxides are formed during combustion by the combination at high temperatures of nitrogen and oxygen naturally found in the air, and from fuel-bound nitrogen. In the case of coal and residual oil, most of the NO_x is derived from fuel nitrogen.[28]

As NO_x production is dependent on combustion regimes, the range of NO_x emissions for a specific fuel is wide and difficult to characterize. For example, the level of NO_x emissions from the same fuel varies considerably by type of plant (e.g., cyclone, wall-fired units or tangential-fired boiler). In addition, design characteristics such as spacing of burners and fuel mixing also affect the rate of NO_x emissions.

The two main approaches to NO_x reduction are modification of the combustion process (by modifying the flame or adding a secondary combustion zone) or by reaction of the NO_x with ammonia. The reaction may take place by injecting ammonia into the ductwork (selective non-catalytic reduction) or in special plants after the boiler containing a catalyst to aid the reaction (selective catalytic reduction).

Low-cost measures described below with NO_x reduction potentials of 15 to 50 percent are low excess air (LEA), overfire air (OA) and low NO_x burners (LNB). Medium-cost measures which achieve NO_x reductions as high as 80 percent on new applications include air staging, flue gas recirculation (FGR), fuel reburning, and staged combustors. Several of these technologies are commercially demonstrated and are also candidates for retrofitting to existing units.[29]

High cost NO_x control measures include advanced techniques which may require additional development and demonstration, such as the copper oxide, NOXSO and SULF-X processes, and technologies which are proven abroad but will require demonstration in Canada, such as selective catalytic reduction (SCR). These technologies are capable of reducing NO_x emissions by over 80 percent. However, they are very expensive and may involve major modifications to existing equipment.

NO_x controls are generally grouped into three categories: combustion modification, flue gas treatment and new combustion techniques. Combustion modifications and flue gas treatment are described below; new combustion techniques such as fluidized bed combustion and integrated gasification combined cycle are described in Appendix B and in the main body of this report.

A.4.1 Combustion Modification[30]

Over the last ten years, boiler manufacturers have developed combustion controls to minimize nitrogen oxide emissions. The approach has been to limit flame temperature by controlling the air distribution to the burning fuel. This may be achieved by stratifying the air supply through each individual burner and/or introducing combustion air supply at different locations in the boiler. This is the most economical approach to NO_x control and is often applied even if further reductions through chemical treatment are required.[31]

Combustion modifications include a variety of techniques to control fuel and air mixing in conventional boilers and/or the use of new combustors (see Table A.5). On retrofits, the applicability of each control measure is dependent on site-specific considerations, including fuel and equipment characteristics such as existing furnace size, age, configuration and burner design and plant layout. This means that the optimum choice of a specific reduction method will require custom engineering services even though the actual technology may have been used in similar applications elsewhere. Consequently, there is considerable variation in the costs of combustion retrofits.

A.4.1.1 Low Excess Air

This process simply involves reducing the amount of excess air supplied to the boiler to aid combustion. Nitrogen oxide reduction potential ranges from 5 to 25 percent and the technology is fully proven and demonstrated. In larger field-erected, multiple-burner boilers used by electric utilities, the large number of burners and the combustion of more difficult fuels such as coal makes implementation of low excess air more complex than for oil- or gas-fired boilers. Low excess air requires equal distribution of air and fuel to each burner to avoid incomplete combustion and increased smoke. The cost of retrofit applications may be more than double the cost for new facilities depicted in Table A.5.

A.4.1.2 Low Nitrogen Oxide Burners

Low NO_x burners are burners which are specifically designed to control air and fuel injection to the boiler, such that the initial mixing of the fuel and combustion air is limited, thereby creating a fuel-rich combustion zone and less NO_x formation. These burners have been widely used and are considered fully proven and demonstrated.

TABLE A.5

SUMMARY OF NO_x CONTROL TECHNOLOGIES FOR COAL-FIRED BOILERS

Technology	Status/Size/ Applicability[a]	NO_x Reduction[b] (%)	NO_x Level Achievable[c] (ng/Joule)	NO_x Reduction Costs[d] ($1988/tonne)
Combustion Modification				
Low Excess Air	D, A	5-25	190	56[e]
Low NO_x Burners	D, A	20-50	130	45-90
Over Fire Air	D, AS	20-40	150	>30
Air Staging	D, AS	50-80	60-130	N/A[f]
Flue Gas Recir.	D, A	20-50	--	200
Fuel Reburning	D, AS	>60	<130	>300
Slagging Combustors	P, AL	>70	60-250	N/A
Advanced Sorbent Injection	D, AS	<90	>85	630-900
Selective Catalytic Reduction	D, A	90	26	2000-4000[g]
Copper Oxide Reduction	R, AS	90	26	N/A
NOXSO Process	R, AS	90	26	N/A
SULF-X Process	R, AS	80	50	N/A
Electron Beam	R, A	>80	50	N/A

SOURCE: Environment Canada, *Control Technologies for Management of NO_x and VOCs in Canada*, Work Sub-Group 6.2 Report (Ottawa, Ontario: Environment Canada, January 1990), p. 6.

[a] The codes are: Status

Status	D:	Demonstrated - Fully available with little additional work needed.
	P:	Pilot scale/needs demonstration or scaling up.
	R:	Needs development and demonstration.
Applicability	A:	Applicable to new and most existing units.
	AS:	Applicable to new and some existing units.
	AN:	Applicable to new units only.
	AL:	Application limited to a class of units.

[b] Note that percent reductions are shown to provide an order to magnitude impression of achievable reductions. Actual reduction will vary depending on the current emissions levels and technical characteristics of each installation. The base levels used was 258 ng/Joule for coal-fired units.

[c] What is achievable will vary somewhat from installation to installation even for similar units; the values are given as typical values only.

[d] Cost figures are approximate only and exclude additional expenses which may be incurred in specific installations such as modifications to boiler pressure parts, major changes to boiler controls, siting costs, etc.

[e] These costs are usually largely offset by energy efficiency improvements.

[f] N/A indicates that cost figures are not available; a dash indicates that an entry is unavailable or that costs are too imprecise to be included.

[g] Personal communication with Environment Canada.

Low NO_x burners may be used in conjunction with flue gas recirculation or air staging to achieve further NO_x emission reductions. On utility multiple-type burners, conventional LNBs can typically achieve NO_x emission reductions of 20 to 40 percent, while newer designs are capable of reductions greater than 50 percent. While these burners may operate as well as conventional burners on boilers specially designed for the modified combustion regime they create, retrofit applications may be limited due to restricted furnace dimensions and the need to minimize incomplete combustion. The costs of using LNB vary depending on the fuel being burned and the size of the application.

A.4.1.3 Overfire Air

This process involves redirection of some combustion air (10 to 20 percent) to a region above the burners so as to minimize the oxygen and peak flame temperature. Overfire air is considered fully proven and demonstrated; NO_x reduction potential is 20 to 40 percent. Overfire air is an effective NO_x reduction technique but may be limited because as with LEA, this process can result in incomplete combustion and increased smoke. Moreover, plant modifications required for retrofitting may be extensive and its applicability to existing plants is therefore somewhat uncertain.

A.4.1.4 Air Staging

On large coal-fired utility boilers, this process involves redirecting 25 to 50 percent of the combustion air either above or through tertiary air ports in the Low NO_x burners themselves. The potential for reduction in conjunction with low NO_x burners can be greater than 70 percent, although lower reduction rates are more typical. The technology is similar to overfire air and many of the same limitations apply.

A.4.1.5 Flue Gas Recirculation

Flue gas recirculation involves recycling a portion of the low oxygen combustion products from the reheater zone or the exhaust stack. The recycled combustion products can be mixed with incoming combustion air or injected into critical zones of the flame. Potential NO_x reduction ranges from 20 to 50 percent. This technology is considered demonstrated and proven, although it is not widely applied in larger units. For large coal-fired utility boilers, FGR is accomplished by returning a portion of the exhaust gases to the burner region of the furnace. The gases dilute all or a selected portion of the combustion air which reduces the peak flame temperature resulting in a reduction in NO_x emissions.

A.4.1.6 Fuel Reburning

This process involves diverting about 10 percent of the primary fuel or introducing a secondary fuel, such as natural gas, into a region above the main burners so that a fuel rich zone is created. In this secondary combustion zone, local chemical reducing conditions convert some of the NO to molecular nitrogen thereby averting the further oxidation of NO to NO_2. Use of a low fuel-nitrogen secondary fuel such as natural gas tends to be more effective than reburning with coal or oil, as natural gas has the advantage of being low in fuel nitrogen and having a shorter burnout time than coal.[32]

A.4.1.7 Slagging Combustors

Slagging combustors are a technology targeted at large utility and industrial coal burning boilers. They appear to be particularly well suited for use on boilers equipped with cyclone furnaces and may also have application in conversion of oil- and gas-fired boilers to coal-firing.

In these devices, coal is partially gasified in a staged combustion chamber outside the boiler and the hot gases are injected into the boiler to complete the combustion process. The current generation of slagging combustors has generally evolved from research conducted in the 1970s. They utilize air staging for NO_x control and up to 80 percent of the coal ash is removed as slag. The remaining ash passes through the furnace and is collected by conventional particulate collection equipment. Several slagging combustor designs also allow for the addition of calcium sorbents either within the burner or after the burner to achieve varying degrees of sulphur capture.

The technology is not yet considered fully proven at utility sizes. The combustors need to be scaled up and demonstrated in utility service to evaluate their durability, reliability and flexibility. While there are no current commercial applications of this technology, several companies are actively working towards commercialization of advanced slagging combustors (see Section A.4.3.2).

A.4.2 Flue Gas Treatment

Flue gas treatment techniques are designed to remove NO_x from exhaust gases by injecting reducing agents into the post-combustion region of a combustion unit. The reducing agents lower NO_x emissions by reducing the NO in the flue gas to molecular nitrogen. Treatment processes that rely on the injection of reducing agents into the stack are referred to as either selective non-catalytic reduction or selective catalytic reduction, depending on the absence or presence of a catalyst.

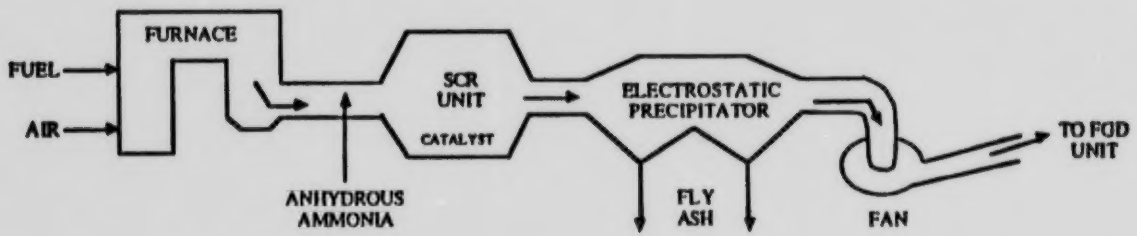
A.4.2.1 Selective Catalytic Reduction

Selective catalytic reduction is a fully demonstrated process in which ammonia is injected into the flue gas upstream of a catalyst grid (see Figure A.5). The catalyst facilitates the conversion of ammonia and nitrogen oxide into elemental nitrogen and water. Uniform mixing of the ammonia and flue gas is essential for successful operation. The advantages of SCR include high reductions in emissions of NO_x, relatively simple equipment, no by-product, and because it is a dry process, minimal efficiency loss.

Prior to SCR, combustion modification was the standard approach to controlling NO_x emissions. However, NO_x reductions due to changes in burner or furnace design reach only 50 percent, with a few exceptions. Increasing concern over NO_x emissions and the tightening of emission standards currently favours the SCR approach, which can achieve reductions of over 90 percent.[33]

Selective catalytic reduction technology has been widely applied to oil-fired units in Japan and is rapidly being adopted in Germany and Austria, where regulations require that plants be equipped with advanced NO_x control equipment. In Germany, a major retrofitting SCR program is underway; the program is designed to reduce overall NO_x emissions by more than 40 percent by 1993. As of December 1986, there were in excess of 2300 MW of capacity using SCR in Germany (see Table A.6); it is expected that the European total of SCR capacity will be 60 000 MW by 1992, mostly within Germany. While these systems have been successfully applied to many gas- and oil-fired boilers, as well as some low-sulphur coal industrial and utility boilers, SCR experience on coal-fired boilers is still rather limited world-wide.

Figure A.5
Selective Catalytic Reduction


FUEL
AIR
FURNACE
ANHYDROUS AMMONIA
SCR UNIT
CATALYST
ELECTROSTATIC PRECIPITATOR
FLY ASH
FAN
TO FGD UNIT

SOURCE: Ontario Hydro, *Thermal Cost Review*, Background Report, October 1989, p. 36.

TABLE A.6

COAL-FUELLED UNITS WITH SCR EQUIPMENT

	Number of Units	MW	Operating Years
Austria	5	1635	4
Germany	33	7470	4
Japan	29	6225	10

SOURCE: Ontario Hydro, *Thermal Cost Review: Background Report* (Toronto, Ontario, October 1989), p. 63.

While it can achieve very high NO_x reductions, SCR has a number of disadvantages. One is its relatively high installation costs. As shown in Table A.5, the cost of reducing NO_x emissions using SCR in a new coal-fired boiler ranges from \$2,000 to \$4,000 per tonne of NO_x. Contributing factors to this expense are the cost of the catalyst, ductwork, and the reactor. Operating and maintenance costs can also be relatively high because the catalyst may need to be replaced every two years.

As a general rule, SCR tends to be more feasible for new boilers and heaters, where the SCR reactor and ducting can be designed into the system. Due to site-specific characteristics, installation costs for SCR retrofits are highly variable and accurate cost estimates can only be made by considering each unit on a case by case basis.

One large uncertainty facing SCR involves problems that arise from using high-sulphur coal. The catalysts that promote destruction of NO_x molecules also encourage oxidation of SO_2 and SO_3, which in turn combine with slip ammonia to form solid and liquid sulphates. These compounds may be deposited in the air preheater where they can interfere with heat transfer, cause corrosion, and plug passages. Contamination of ash with ammonia by-products is also possible which may increase waste disposal costs or hamper sale of the ash by-product. These problems are less pronounced with low- and medium-sulphur coals typical of Japanese and German applications. More research on these and other issues related to coal quality and differences between foreign and domestic operating practices is needed before SCR technology is established for Canadian utility applications.[34]

Practical considerations include:

- certain fuel impurities and components in the ash, such as arsenic, can poison and/or erode the catalyst and seriously shorten its lifetime. This is extremely important as the catalyst is a substantial portion of the cost of the system and needs replacing every few years;
- good operation, maintenance and control is required of ammonia injection and flue gas mixing systems, or fouling and plugging of the catalyst and air heater will occur, causing ammonia to be vented with the flue gas; and
- there has been limited experience in using these systems with high-sulphur North American coals.

A.4.2.2 Selective Non-Catalytic Reduction

Another post-combustion NO_x removal technique recently commercialized is SNCR or advanced sorbent injection, where NO_x removal takes place at higher temperatures and without a catalyst.

Advanced sorbent injection involves the addition of reactants such as urea in solution to the cooler upper-furnace area. Proprietary enhancer chemicals control the formation of ammonia which is a by-product of the reaction of urea and NO_x and control the reaction conditions. When combined with the injection of a calcium-containing sorbent (e.g., limestone, hydrated lime or dolomite) in a dry or slurry form, the process can remove substantial quantities of both SO_2 and NO_x. These systems are considered demonstrated in commercial scale applications in the U.S., Germany and Japan. In Canada, an urea and limestone slurry has undergone pilot-scale testing in Ontario. The process is claimed to be capable of up to 90 percent NO_x reductions and 85 percent SO_2 reductions. In a large boiler, the NO_x removal cost is estimated to be about half that of SCR per tonne of NO_x reduction.

A major advantage of SNCR compared to SCR is that catalysts are not required, which lowers operating costs and reduces space requirements. However, SNCR has several potential problems. The process can release ammonia; it also produces ammonia sulphate, as a by-product, which can disrupt the system; corrosion of boiler equipment has not been resolved; and there are problems with proper construction of the units. While the technology has been successful in gas- and oil-fired utility boilers in Japan, the applicability of SNCR to coal units and, in particular, large-scale coal-fired units has not been demonstrated. It appears that SNCR may be most economic for small industrial furnace applications.[35]

Practical considerations include:

- the use of urea sorbents introduces the possibility that unreacted ammonia will be released to the environment; this may also cause fouling problems in air preheaters;
- there is no full-scale Canadian experience on Canadian coals, although there is some Canadian experience with U.S. coals; and
- it is possible that existing furnaces may not contain an appropriately located "temperature window" for effective operation of the sorbents.

A.4.3 Combined SO_2 and NO_x Control

Several technologies are under development that simultaneously achieve moderate to high removal rates of both sulphur dioxide and nitrogen oxides. These technologies include limestone injection multi-stage burners (LIMB), advanced slagging combustors, gas reburning coupled with in-duct sorbent injection (GR-SI), electron beam (E-beam), copper oxide, NOXSO and SULF-X.

Many of these systems regenerate the sorbent and recover sulphur or sulphuric acid from the flue gas and many are also suitable for retrofit. Demonstrations have shown SO_2 removal of 90 percent or more and NO_x removal up to 80 percent. A fundamental advantage of such systems is a combined lower average cost compared to those for separate control systems with comparable levels of SO_2 and NO_x reductions. Furthermore, they may be designed to use less energy than conventional FGD, and unlike FGD do not produce large quantities of waste.[36]

A.4.3.1 Limestone Injection Multi-Stage Burners

The limestone injection multi-stage burner process combines the injection of dry sorbents into the boiler for direct capture of sulphur dioxide from the combustion gases and the use of low NO_x burners in which staged combustion is used for NO_x control. It is a relatively simple system and attractive for retrofit applications.

Limestone injection multi-stage burner should achieve 30 to 50 percent reductions in SO_2 and 50 percent reduction in NO_x emissions. An obvious drawback is that reductions at this level do not satisfy many existing standards for new plants.

A.4.3.2 Advanced Slagging Combustors

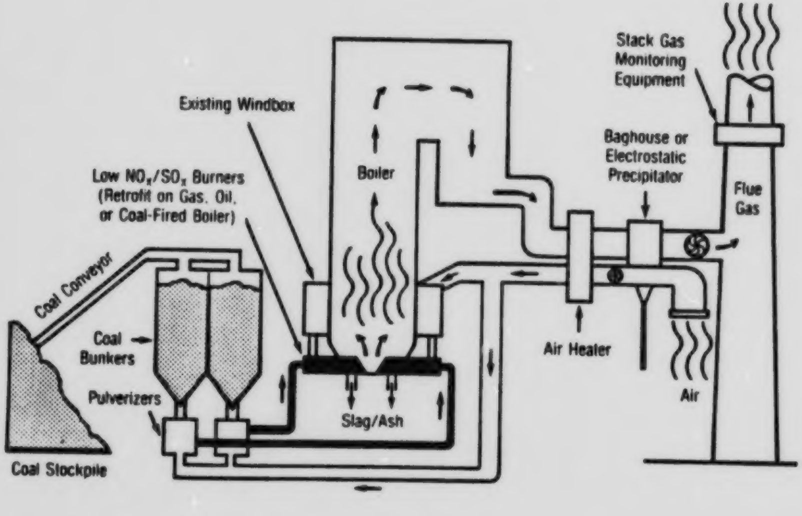
Slagging combustors partially gasify coal in a staged combustion chamber outside the boiler and recover sulphur and ash as a molten slag. Many of these high intensity burners were used in the United States between 1940 and 1970; however, they were largely retired in the early 1970s because of their poor control of SO_2 and NO_x emissions.

Advanced slagging combustors are based on the original concept but incorporate techniques to reduce NO_x and SO_2 from coal-derived fuel before it is injected into utility boilers. The primary advanced combustion technology under development uses slagging cyclone combustors that offer the potential to reduce SO_2 emissions by 70 to 90 percent in a pulverized coal boiler. This reduction is achieved by introducing limestone sorbent into the combustor or into the combustion gases exiting the combustor. If the sorbent is injected into the combustor, most of the limestone and captured sulphur exits with the molten slag, which is a solid waste. If the sorbent is injected into the hot combustor gases, or if significant amounts of sorbent are carried into the boiler, it is captured in the particulate clean-up system. Removal of ash as slag rejection is 70 to 90 percent. NO_x reduction is achieved in the slagging cyclone combustor by air staging with combustion being completed in the boiler where additional air is introduced. Overall, NO_x reduction of 50 to 70 percent is achieved.[37]

One example of promising research on slagging combustors is the Low SO_x/NO_x burner (LNSB). The burner is a multi-stage, slagging-type combustor intended to control NO_x and SO_2 simultaneously (see Figure A.6). It was developed initially by Rockwell International in the U.S., but the technology is now owned by TransAlta Resources Investment Corporation of Calgary, Canada.

The LNS burner uses advanced combustion concepts to reduce SO_2 emission from coal combustion by between 70 and 90 percent while leaving thermal efficiency unaffected, an advantage over FGD processes. Preliminary studies indicate that the capital cost of equipping coal-fired boilers with LNSB should be in the order of

Figure A.6
Low NO_x/SO_x Burner Example Installation


Stack Gas
Monitoring
Equipment
Existing Windbox
Baghouse or
Electrostatic
Precipitator
Low NO_x/SO_x Burners
(Retrofit on Gas, Oil,
or Coal-Fired Boiler)
Boiler
Flue
Gas
Coal Conveyor
Coal
Bunkers
Air Heater
Pulverizers
Air
Slag/Ash
Coal Stockpile

SOURCE: Alberta Department of Energy, *Development of Clean Coal Technologies for Alberta*, p. 7.

40 percent of the capital costs and 20 percent of the operating costs for similar control of NO_x and SO_2 using state-of-the-art flue gas treatment systems.[38]

The LNSB has received funding for demonstration as part of the United States Department of Energy's Clean Coal Technology Program for retrofit of a 33 MW utility cyclone boiler in Marion, Illinois. In addition, TransAlta and Esso Resources are evaluating the LNSB for coal burning to produce steam for heavy oil recovery at Esso's Cold Lake project, in Alberta, Canada.

A.4.3.3 Gas Reburning/Sorbent Injection

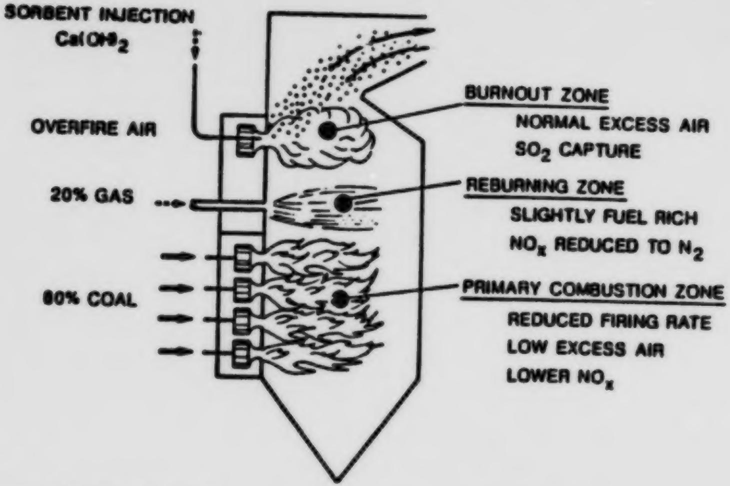
This concept is an integration of two developmental technologies: gas reburning for NO_x control in conjunction with sorbent injection for SO_2 control (see Figure A.7). As noted earlier, reburning involves the injection of natural gas above the main heat release zone to reduce NO_x to molecular nitrogen. With sorbent injection, low cost, calcium-based sorbents are injected at one or more locations as the combustion gases pass from the radiant furnace through the convective process to the air heater. The sorbent contained in the fly ash is removed from the flue gas in an existing precipitator or baghouse.

The GR-SI process provides an alternative technology to conventional wet FGD processes and is suitable for retrofit applications; it also requires less space. While reburning can be performed with any fuel, pilot studies indicate that fuels with little or no fuel-bound nitrogen, such as natural gas, can achieve greater NO_x reductions. A NO_x reduction capability of 60 percent when using 15 to 20 percent natural gas as the reburning fuel has been demonstrated. Greater SO_2 reduction also results from the use of sulphur-free natural gas for reburning.[39]

Gas reburning with sorbent injection has several attributes. A moderate amount of SO_2 and NO_x reduction can be obtained at less cost than FGD and a dry and non-toxic solid waste is produced. The technology can also be easily retrofitted to an existing unit without requiring a major investment or a lengthy outage. While there is a small decrease in efficiency due to the energy needed to operate the equipment, there is an improvement in the operation of the boiler because of the reduced loading of ash into the burner.[40]

Figure A.7

Gas Reburning - Sorbent Injection


SORBENT INJECTION
$Ca(OH)_2$
OVERFIRE AIR
20% GAS
80% COAL
BURNOUT ZONE
NORMAL EXCESS AIR
SO_2 CAPTURE
REBURNING ZONE
SLIGHTLY FUEL RICH
NO_x REDUCED TO N_2
PRIMARY COMBUSTION ZONE
REDUCED FIRING RATE
LOW EXCESS AIR
LOWER NO_x

SOURCE: B.A. Folsum, W. Bartok, R. Payne, and D. Moyeda, "Field Evaluation and Gas Reburning-Sorbent Injection Technology for NO_x and SO_2 Emission Control for Coal-Fired Utilities Boilers," Figure 1, *Energy Technology XV*, February 1988.

A.4.3.4 NOXSO Process

In this process, flue gases enter a fluidized bed absorber containing a sorbent composed of sodium carbonate coated alumina particles. Sulphur dioxide is captured in the form of sodium sulphate and NO_x is captured in the form of sodium nitrate.

The spent sorbent is continuously withdrawn from the absorber and regenerated by heating and exposure to a reducing gas such as methane or hydrogen. This process is claimed to be capable of simultaneous removal of SO_2 and NO_x in the 90 percent range. To date, no full-scale unit is in operation, although it has been pilot tested at coal-burning power plants, and a full-scale unit is planned.

A.4.3.5 SULF-X Process

This is a complex wet absorption process in which a wet slurry of finely divided ferrous sulphide is used to absorb SO_2 and remove NO_x from flue gas. Sulphur is recovered as elemental sulphur and NO_x is converted to molecular nitrogen. The process is claimed to remove over 90 percent of SO_2 and about 80 percent of NO_x. No definite cost estimates are available, but costs are likely to be high due to process complexity. To date, a pilot-scale demonstration has been carried out on a small coal-fired boiler; a larger demonstration was planned but has been indefinitely deferred. The process is not considered commercially proven at this time.

A.4.4 Advanced Systems for NO_x and SO_2 Control

In addition to the above, several advanced flue gas systems are also under development. Each of these systems has the potential to reduce both SO_2 and NO_x by 90 percent. Moreover, these systems have the capability to either regenerate the sorbent or produce a by-product (e.g., fertilizer) and, unlike flue gas scrubbers, these processes do not produce large quantities of waste. Two systems are currently classified as advanced flue gas cleanup technologies--E-beam and copper oxide reduction.

A.4.4.1 Electron Beam

Two variations of the electron beam process are being tested in Germany, Japan and the United States--an ammonia-based process and a lime-based process. In the ammonia process, the flue gas is first cooled and humidified with water in a spray cooler. Ammonia gas is then added and the flue gas passes through an electron beam, which converts SO_2 and NO_x to sulphuric acid and nitric acid. These acids react with the ammonia to form ammonia sulfate and ammonia nitrate. The reaction products are captured in a dust collector and may be used for the manufacture of fertilizer.

The process has several advantages over competing systems: (1) low cost, especially on retrofits; (2) low power consumption; (3) liquid wastes disposal is eliminated; and (4) the process produces a by-product which can be used as a fertilizer.

In the lime process, the flue gas first travels through a spray dryer to be cooled and humidified by lime slurry evaporation. In the spray dryer, some of the SO_2 reacts with calcium hydroxide to form calcium sulfite. The treated gas leaving the spray dryer then passes through an electron beam which converts the NO_x and the remaining SO_2 to nitric and sulfuric acid. To complete the process, the flue gas passes through a fabric filter in which the sulfuric and nitric acid react with calcium hydroxide to produce calcium sulfate and calcium nitrate. These reaction products and the fly ash are collected by the fabric filter. The waste products would then be hydrated with water and disposed of in a landfill. This process has additional requirements for a calcium reagent spray dryer and produces solid waste that must be collected in a baghouse. As well, it produces sludge and wastewater which need treatment and safe disposal. As a result, the capital and operating costs are expected to be higher than the ammonia based process.

A.4.4.2 Copper Oxide Reduction

This method uses a dry process based on reactions with SO_2 to form copper sulphate. Copper sulphate then becomes a catalyst for the selective reduction of nitrogen oxides to molecular nitrogen by reaction with ammonia. The sulphate is reduced with a suitable gas such as hydrogen to regenerate copper oxide, which is then recycled and reoxidized on exposure to the flue gas. Removal efficiencies for both SO_2 and NO_x are reportedly in the 90 percent range.

While initially designed as a method for removing SO_2 in new power plants, this process can also be retrofitted on existing coal-fired plants.

A.5 By-Product and Wastes

Most of the technologies for the control of air pollution generate solid waste by-products. Efforts to increase the efficiency of emissions reduction in response to more stringent emissions control is leading to higher costs and greater waste volumes. As the volume of solid wastes increases, it is expected that disposal will become increasingly difficult. This may alter the balance between competing pollution control technologies in favour of those that produce useable by-products.[41]

In some countries, the disposal of wastes from FGD and sorbent injection is already a key issue. For example, in Japan and Germany, legislation prohibits dumping when re-use of wastes is possible. As a result, systems producing gypsum, which can be sold to the building industry, have been preferred. However, some objections to gypsum production are being raised due to limited market size compared with the large quantities produced by power plants, and the large volume of limestone reagent required. Recently concern has also arisen over the possible hazardousness of the wastes.[42]

As a result of growing regional concern over waste management, regenerable FGD processes are the object of increasing interest. However, regenerable systems tend to be more complex, less well-developed, and more costly--thus, most FGD installed today continues to be of the wet lime/limestone process producing either gypsum residue or saleable gypsum.[43]

A.6 The Canadian Setting

There are a wide range of control measures which can be applied to reduce the production or emissions of SO_2 that arise from the production of metals or the combustion of fossil fuels. Proven technologies available to reduce SO_2 emissions from smelters, power plants and other sources have been applied or are expected to be implemented within a few years. By 1994, state-of-the-art technologies will be in place in Canadian non-ferrous smelters. Flue gas desulphurization scrubbers (wet limestone type) are planned at several power plants. In Ontario, between 2 and 12 coal-fired units will be retrofitted depending on load growth, while in New Brunswick new coal-fired units with scrubbers are planned and one is now under construction at Belledune. For these scrubbers, commercial gypsum recovery is being investigated.

While these control technologies will play a significant role, particularly for existing plants, they impose an energy penalty and pose other environmental problems, such as sludge disposal and water contamination. In the longer term, new control technologies which permit simultaneous treatment of SO_2 and NO_x, such as the Copper Oxide process, may replace conventional scrubbers if current R&D programs prove to be successful. However, the need to address issues such as SO_2, in conjunction with other environmental concerns such as NO_x and CO_2 and energy efficiency, means that in the long run new energy production technologies will replace the current conventional plants.[44]

Major advances in NO_x control technologies are in use in Japan, Germany and California. However, some of the most promising technologies require further research, development and demonstration for Canadian fuels under Canadian conditions.[45,46]

Of the various options for controlling emissions (pre-combustion, combustion and post-combustion), combustion technologies present the greatest opportunities for increases in thermal efficiency and net reductions in CO_2 and other radiative gas emissions.[47] Owing to the fact that coal-fired electrical plants are in the order of 35 percent energy efficient, every percentage improvement in efficiency has a leveraged impact on the reduction of emissions. Fortunately, many of the technologies that offer energy efficiency improvements also result in significantly improved methods of controlling SO_2 and NO_x emissions. The next appendix examines some of these advanced generation technologies and their potential for reducing emissions and improving energy efficiency.

Footnotes

[1] International Energy Agency, *Emission Controls in Electricity Generation and Industry* (Paris, France: Organisation for Economic Co-operation and Development, 1988), p. 58.

[2] Alberta Department of Energy, Office of Coal Research and Technology, *Development of Clean Coal Technologies for Alberta* (Edmonton, Alberta: Department of Energy), p. 4.

[3] United States, National Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," Vol. II - Emissions and Controls (Washington, D.C.: National Acid Precipitation Assessment Program, 1987), p. 2-6.

[4] Ibid., p. 2-7.

[5] Environment Canada, *LRTAP 1990 Assessment Report - Emissions and Controls (Draft)* (Ottawa, Ontario: Environment Canada, February 1990), p. 2-79.

[6] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-7.

[7] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-79.

[8] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-6.

[9] International Energy Agency, *The Clean Use of Coal: A Technology Review* (Paris, France: Organisation for Economic Co-operation and Development, 1985), p. 14. See also K. Morgan MacRae, *An Assessment of the Potential for Coal-Derived Syncrudes in Canada*, CERI Study No. 27 (Calgary, Alberta: Canadian Energy Research Institute, June 1988).

[10] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-42.

[11] Ibid., p. 2-43.

[12] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 61.

[13] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-83.

[14] Alberta Department of Energy, Office of Coal Research and Technology, *Development of Clean Coal Technologies for Alberta*, p. 4.

[15] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-19.

[16] Ibid., p. 2-47.

[17] Ontario Hydro, *Thermal Cost Review* (Toronto, Ontario: October 1989), p. 30.

[18] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-3.

[19] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, p. 63.

[20] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-16.

[21] Ibid., p. 2-48.

[22] Ontario Hydro, *Thermal Cost Review*, 1989, p. 62.

[23] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-81.

[24] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-50.

[25] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-83.

[26] Ontario Hydro, *Thermal Cost Review*, 1989, p. 31.

[27] Union Carbide Canada Limited, "Reducing Acid Rain Emission Target of Pilot Plant Project," Press Release (Toronto, Ontario: Union Carbide Canada Limited, April 11, 1990) and Leo E. Hakka and J. Stuart Burgess, "The CANSOLV FGD Process," Presentation to *EPRI/EPA SO_2 Control Symposium*, New Orleans, Louisiana, May 1990.

[28] United States, Environmental Protection Agency, *Policy Options for Stabilizing Global Climate* (Washington, D.C.: EPA, February 22, 1989), p. VII-132.

[29] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds*

(VOC) in Canada: Work Sub-Group 6.2 Report, Stationary Sources - NO_x (Ottawa, Ontario: Environment Canada, January 1990), p. 2.

[30] Unless otherwise noted, the information presented below has been abstracted from the report published by Environment Canada, entitled *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) in Canada:* Work Sub-Group 6.2 Report, Stationary Sources - NO_x (Ottawa, Ontario: Environment Canada, January 1990).

[31] Ontario Hydro, *Thermal Cost Review*, 1989, pp. 35-36.

[32] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-90.

[33] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 66.

[34] Electric Power Research Institute, "Retrofit Strategies for NO_x Control," *EPRI Journal* (March 1987): p. 28.

[35] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 67.

[36] Ibid., p. 68.

[37] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-55.

[38] Alberta Department of Energy, Office of Coal Research and Technology, *Development of Clean Coal Technologies for Alberta*, pp. 7-8.

[39] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, p. 2-56.

[40] Ibid., p. 2-57.

[41] International Energy Agency, *The Clean Use of Coal: A Technology Review*, 1985, p. 7.

[42] Dr. Jan Vernon, "Air Pollution Control and Its Impact on Coal Use," *Energy Exploration and Exploitation*, (Essex, United Kingdom, Multi-Scienc Publishing Co. Ltd, 1988) p. 459.

[43] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, p. 68.

[44] Environment Canada, *Emissions and Controls (Draft)* February 1990, p. 2-42.

[45] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) in Canada*, 1990, p. 27.

[46] Ontario Hydro, *Thermal Cost Review*, 1989, pp. 35-36.

[47] Coal Association of Canada, *Brief on Global Warming to House of Commons Standing Committee on Environment* (Calgary, Alberta: Coal Association of Canada, December 14, 1989).

APPENDIX B

ADVANCED GENERATION TECHNOLOGIES

Appendix B

ADVANCED GENERATION TECHNOLOGIES

B.1 Introduction

A number of advanced coal generation technologies are under development which offer significant energy and environmental benefits as compared to existing coal-fired power plants. On the energy side, these technologies offer improved energy use through high combustion efficiency and the ability to burn low-quality fuels such as coal washery wastes, high-sulphur coal and petroleum coke. On the environmental side, sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions, in particular, are reduced to a high degree through the combustion process itself, and thereby avoid installation of costly technologies such as flue gas desulphurization (FGD) for SO_2 control and selective catalytic reduction (SCR) for NO_x control. The higher efficiency of these technologies relative to conventional pulverized coal-fired power plants also reduces production of carbon dioxide (CO_2)--a major greenhouse gas.[1]

The most mature of this generation of generating technologies is atmospheric fluidized bed combustion (AFBC) which is in growing commercial use, though experience is limited so far to small units. Pressurized fluidized bed combustion (PFBC) is in the experimental phase, with a number of small units in operation and demonstration units planned.

There is also increased interest in coal gasification, particularly for utility applications, where it is coupled with the combined cycle generation of power in a concept termed integrated gasification combined cycle (IGCC). This form of power generation is believed to be one of the most promising, advanced technologies for electric utilities in the future. Continued progress in developing high-efficiency gas turbines and system improvements stemming from wider demonstration of IGCC promise further, significant improvements in IGCC technology.

This appendix gives a general overview of these technologies, speaks to their attributes and applications, and identifies research which seems likely to enhance their future performance.

B.2 Atmospheric Fluidized Bed Combustion

B.2.1 Process Description

A fluidized bed is a mass or "bed" of small particles--solid fuel, ash and sorbents (used for sulphur removal)--through which flow large volumes of air and combustion gases. The gases move through the bed at velocities sufficient to cause the mass of particles to expand and behave like a fluid.

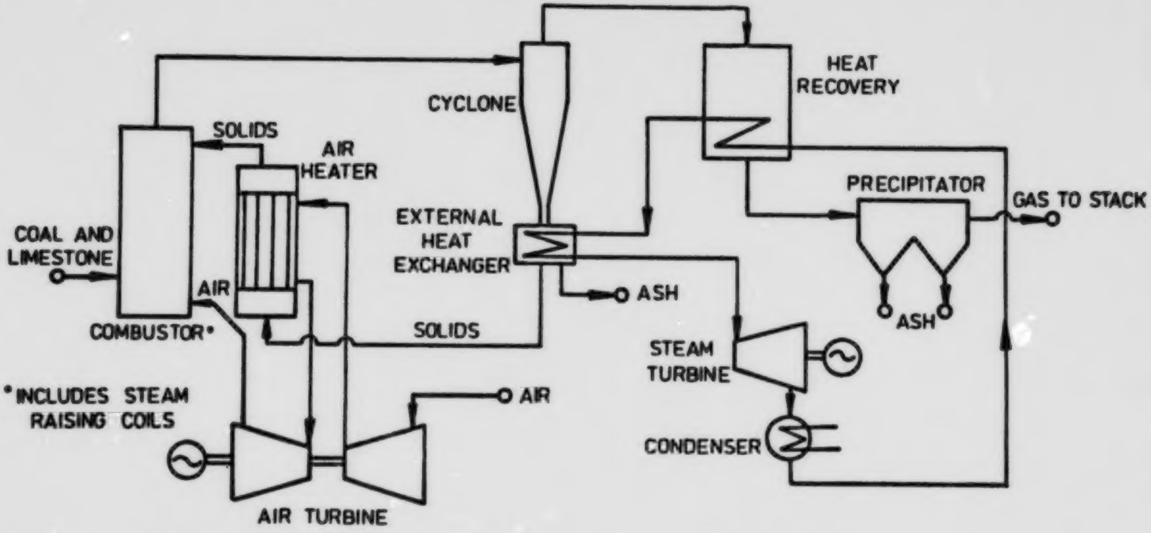
In the typical AFBC, unburned solid fuel is regularly fed into the bed and mixed with the bed's hot particles bringing about combustion. Tubes with flowing water that are located within and/or above the bed in the flue gas path are heated to form steam which is then sent to a steam turbine for the generation of electricity (see Figure B.1).

If the fuel contains substantial quantities of sulphur, a chemically active "sorbent" such as limestone is fed into the bed to react with the sulphur. The sorbent captures the sulphur before it escapes from the bed with the combustion gases. This capability to capture sulphur "in situ" eliminates the need for expensive add-on sulphur-removal equipment such as FGD and is one of the most attractive features of AFBC. Atmospheric fluidized bed combustion solid waste is dry, so that handling and disposal procedures are greatly simplified compared to the wet sludge resulting from FGD systems. A baghouse or precipitators collect particulate matter from the flue gas before it is released to the atmosphere.[2]

For fluidization to occur, the bed solids must remain in the form of discrete particles. To keep them from agglomerating or melting, FBCs generally operate at relatively low temperatures (815-875°C), compared to conventional boilers burning pulverized coal. This lower temperature operation, together with the complete mixing which results from fluidization means: (1) capture of SO_2 by the bed particles is efficient; and (2) ash (non-combustible materials) in the coal does not reach its melting point and thus never forms the slag that tends to foul and corrode high temperature boilers.[3]

Although fluidization conditions represent a continuum, AFBC boiler designs have been generally classified as either bubbling

Figure B.1
Atmospheric Circulating Bed Cycle


CYCLONE
HEAT RECOVERY
SOLIDS
AIR HEATER
EXTERNAL HEAT EXCHANGER
PRECIPITATOR
GAS TO STACK
COAL AND LIMESTONE
AIR
ASH
ASH
COMBUSTOR*
SOLIDS
STEAM TURBINE
*INCLUDES STEAM RAISING COILS
AIR
CONDENSER
AIR TURBINE

SOURCE: A.D. Dainton, J.S. Harrison, and J. Holmes, "Advanced Cycles for Coal-Fired Power Generation," *8th International Conference on Coal Research*, Tokyo, Japan, October 16-20, 1988.

or circulating. In bubbling-bed AFBC boilers, a relatively dense bed of solids is maintained in the lower portion of the furnace by firing coal and limestone top sizes of 30 millimetres and by operating at nominal furnace gas throughput velocities of up to 4 metres/second. Combustion efficiencies in excess of 95 percent and sulphur capture efficiencies of up to 90 percent are achievable. The bed temperature, typically about 850°C to maximize sulphur capture, also suppresses thermal NO_x and results in NO_x emissions which are 50 to 80 percent lower than those produced in conventional coal flames.[4,5]

In the circulating AFBC unit, fluidization velocities of up to 8 metres per second and 8 millimetre coal is used in a bed of sorbent material. Air injected from below the bed at high velocity fluidizes fuel and sorbent particles and lifts the burning mass the full height of the boiler. After releasing heat to the water-walls in the boiler, the combustion gases flow into hot cyclones and then through the superheater (see Figure B.1). Particles removed by the cyclones are then recirculated to the original combustion chamber, where they are mixed with fresh fuel and limestone. The long furnace retention time for the fuel and limestone and their continuous circulation allows for complete fuel combustion and very high sulphur dioxide capture.[6]

B.2.2 Attributes of AFBC

Fluidized bed combustion offers several advantages in meeting the increasingly stringent environmental requirements of coal use. The combustion temperature in a FBC system is maintained at a lower level than conventional boilers, facilitating the absorption of sulphur by the limestone and also reducing NO_x emissions. As a consequence, AFBC largely eliminates dependence on expensive pre- and post-combustion clean-up processes, such as FGD and SCR.

The attributes of fluidized bed combustion may be summarized as:

- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- The flue gases require only particulate removal.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of sulphur dioxide. Sulphur capture efficiencies of up to 90 percent are achievable.[7]

- Atmospheric fluidized bed combustion results in NO_x emissions 50 to 80 percent lower than produced in conventional coal flames, as combustion occurs at substantially lower and more evenly distributed temperatures.

- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.

- Low-grade fuels such as coal washery wastes, high-sulphur coals and petroleum coke can be used without causing slagging and fouling problems.

- Atmospheric fluidized bed combustion produces larger quantities of waste than FGD systems; however, it is a dry and non-toxic material that can be used for road or building construction.

- Atmospheric Fluidized Bed Combustion offers attractive economics for repowering and retrofitting older existing plants. Repowering extends station life, increases plant capacity and lowers emissions.

When compared to conventional pulverized coal plants with flue gas desulphurization, AFBC technology has the potential to produce inherently low NO_x emissions and to cost about the same per kilowatt, although costs are currently higher on small units and CO_2 released to the atmosphere increases somewhat due to use of limestone. Fuel flexibility adds an additional cost saving dimension.[8]

B.2.2.1 Bubbling Versus Circulating

The circulating bed, though somewhat more expensive, has generally been selected over the bubbling-bed variety for utility use due to perceived simplicity, flexibility and reliability. The circulating system has continued to lead in FBC technical advancement, as the recycling of the combustion reactants in this system increases the reaction time over that of the bubbling type of systems.

Applications requiring low NO_x emissions are also particularly suited to the circulating design. Because this design is operated in a mode of staged combustion (e.g., the air is introduced at various elevations in the combustor), NO_x emissions are typically one-third to one-half of the bubbling-bed variety. In addition, experience in Europe indicates that the circulating AFBC has the greatest sulphur capture potential (95 percent).

B.2.3 Operating Experience

As shown in Table B.1, the production and use of FBC technology has increased rapidly, although capacity is limited to small size units. Coal fuels 65 percent of the generators, with wood, peat and waste (including petroleum coke) fuelling the remaining capacity. These were 1881 MW of coal-fuelled capacity by December 1986, and a further 750 MW were added in the United States and 300 MW in Germany by 1988 (see Table B.2).[9]

TABLE B.1

GROWTH OF COAL-FUELLED FBC

	Number of Units	Total Capacity (MW)	Average Unit Size (MW)
- 1975	4	9	2
1976-79	16	67	4
1980-83	105	655	6
1984-86	107	1150	11
TOTAL	232	1881	8

SOURCE: Ontario Hydro, *Thermal Cost Review*, vol. I, (Toronto, Ontario: Ontario Hydro) p. 64.

TABLE B.2

INSTALLED COAL-FUELLED FBC CAPACITY BY COUNTRY

Country	Capacity (MW)	Share (%)
Germany	281	15
Japan	187	10
Scandinavia	221	12
United Kingdom	224	13
United States	584	31
Other	364	19
TOTAL	1881	100

SOURCE: Ontario Hydro, *Thermal Cost Review*, vol. I, (Toronto, Ontario: Ontario Hydro) p. 64.

In the United States, electric utilities have embarked on a programme to demonstrate AFBC technology by building and operating utility-size units. The main aim is to achieve a better understanding of fluid dynamics, SO_2 and NO_x capture, and the leaching characteristics of solid wastes.

Five AFBC demonstration projects are presently in various stages of development:[10]

- Northern States Power, Black Dog Station, 125-MW, bubbling-bed AFBC;
- Colorado-Ute Electric Association, Nucla Station, 110-MW, circulating-bed AFBC;
- Tennessee Valley Authority, Shawnee Station, 169-MW, bubbling-bed AFBC;
- Wisconsin Electric Power, Oak Creek Units 1-4, 500-MW (total), bubbling-bed AFBC; and
- Montana-Dakota Utilities Co., R.M. Heskett Station, 80-MW, bubbling-bed AFBC.

In Canada, research on fluidized bed combustion is in progress at the two 18 000 kg/hr bubbling AFBC boilers at the Canadian Forces Base at Summerside, Prince Edward Island and at the 20-MW circulating AFBC Unit at Chatham, New Brunswick. Sulphur capture at the Chatham unit has exceeded 90 percent and NO_x emissions have been less than 100 ppm. In addition, Canada's first commercial-scale demonstration project is proceeding in Nova Scotia. Nova Scotia Power is planning to have a circulating AFBC unit of 150 MW in operation at Point Aconi, Nova Scotia in 1993. The Canadian Electrical Association is also sponsoring studies on the disposal, utilization and re-use of wastes from circulating AFBC units.[11]

B.2.4 Future Development

While commercial-scale demonstration projects are underway to prove the potential role of AFBC, its costs and environmental merits, most utility planners believe that atmospheric fluidized bed combustion will not play a significant role in electric utility planning until after the year 2000. However, its prospects are good for small non-utility plants where a source of waste or lower quality, low cost fuel is available.[12]

To prove up the AFBC technology, current research and development work is aimed at:

- improving limestone utilization;
- gaining experience with a variety of coals;
- reducing capital cost through reductions in boiler size and reduced auxiliary power requirements;
- improving operational flexibility and reliability; and
- developing waste disposal and waste product utilization options.

B.3 Pressurized Fluidized Bed

B.3.1 Process Description

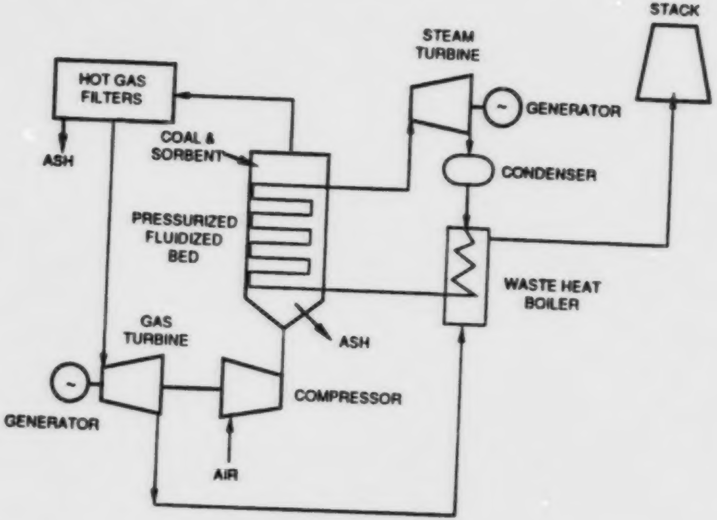
As with AFBC, PFBC takes place in a bed of particles of fuel and sorbent material fluidized by a stream of combustion air and combustion gases. The major difference with PFBC is that the entire process takes place in a vessel at pressures from eight to twenty atmospheres.

During combustion, tubes with flowing water that are located within the bed are heated to form steam which is then sent to a steam turbine for the generation of electricity (as in the typical AFBC). Because of the elevated pressures at which they operate, PFBC system efficiency is increased relative to AFBC through the incorporation of a gas turbine to recover additional energy from the pressurized products of combustion (see Figure B.2). The combined electricity conversion efficiency realized in this combined cycle configuration (40 percent or more) is higher than either cycle is capable of separately. As well, pressurized combustion enhances air/fuel mixing, combustion kinetics, and pollution abatement. Moreover, as with AFBC, PFBC combustor efficiency is not degraded by parasitic losses from downstream sulphur removal equipment (e.g., FGD).

B.3.2 Attributes of PFBC

A PFBC system has several advantages over AFBC. Due to its smaller size and higher operating pressure, PFBC lends itself to modular fabrication and construction. This allows small, incremental units to be brought on stream as electrical load growth develops, thereby shortening construction time and lowering financing

Figure B.2
PFBC Combined Cycle Plant


STACK
STEAM TURBINE
HOT GAS FILTERS
GENERATOR
ASH
COAL & SORBENT
CONDENSER
PRESSURIZED FLUIDIZED BED
WASTE HEAT BOILER
GAS TURBINE
ASH
COMPRESSOR
GENERATOR
AIR

SOURCE: K.V. Thombimuthu, *Environmental Benefits of Coal Liquid Fuels* (Ottawa, Ontario: CANMET, 1989), p. 22.

requirements. Pressurized fluidized bed combustion operating characteristics are well-suited for base-load applications either in new units or in repowered facilities.

The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and in situ capture of sulphur dioxide, eliminating the need for add-on SO_2 removal units.[13] The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures which reduces formation of nitrogen oxides. These emissions can be further reduced by injecting reducing agents in small quantities.[14]

The main advantage of PFBC is the possibility of using the hot, pressurized off-gas to power a gas turbine, as well as generating steam for a steam turbine, thereby increasing the overall conversion efficiency. In this combined cycle, power generation efficiencies of 42 to 44 percent are anticipated, resulting in fuel saving of over 10 percent compared with plants with flue gas cleaning.

The attributes of PFBC may be summarized as:

- Gases require hot particulate clean-up before entering the gas turbine. No flue gas clean-up is required.
- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- Sulphur capture levels of 98 to 99 percent can be achieved.
- Elevated pressures permit higher combustion intensity and reduce the size of the unit.
- The space required for repowering a conventional coal-fired power plant with PFBC is of the same order of magnitude as would be required for a flue gas scrubber.
- All types of coal or coal wastes can be burned.
- The waste generated has been found suitable for road building, the manufacture of synthetic gravel, formed bricks and tiles.[15]
- CO_2 emissions per kW.h for a given coal are reduced with PFBC (compared to AFBC or a conventional unit with FGD) owing to its higher thermal efficiency.

- Pressurized fluidized bed combustion can achieve a higher rate of sulphur capture per unit of limestone than AFBC.
- Pressurized fluidized bed combustion lends itself to construction in relatively small blocks of capacity, 100 MW or so at a time, without sacrificing economies of scale. This allows staged construction to match load growth in small steps.[16,17]

B.3.3 Operating Experience

Currently, the principal demonstration facility for PFBC technology is a 25-MW pilot plant in Grimethorpe, England which was commissioned in 1980. However, a number of units in the 70-80 MW capacity range will shortly be operational at utility sites in Sweden, Spain and the United States (see Table B.3). These units are scheduled for startup in 1990 and 1991.

TABLE B.3

PFBC PROJECTS - SUMMARY

Site	Escatron	TIDD	Värtan
Purpose	PFBC DEMO	PFBC DEMO	COGENERATION
Output	79 MWe	73 MWe	130 MWe+210 MWt
Coal Type	Lignite	Ohio	Polish
Coal-S	7%	4%	1%
Ash	36%	10%	15%
Coal Feed	Dry	Paste	Paste
Sorbent Feed	Dry	Dry	Mixed as Paste
Sorbent	Limestone	Dolomite	Limestone, Dolomite
Excess Air	15%	25%	25%
Fluidizing Velocity	0.9 m/s	0.9 m/s	0.9 m/s
Bed Height	3.5 m	3.5 m	3.5 m
Pressure	12 Bar	12 Bar	12 Bar
Steam Turbine	Existing	Existing	New Turbine
Start-Up Date	Early 1990	Mid-1990	Mid-1990

SOURCE: Krishna K. Pillai, "Commercial Status and Further Development of PFBC," in *EPRI Proceedings 1989 Conference on Technologies for Producing Electricity in the Twenty-First Century* (San Francisco, California: Electric Power Research Institute, October 30-November 2, 1989).

American Electric Power is installing a PFBC module for the repowering of its mothballed Tidd power plant at Brilliant, Ohio. This facility is to be a demonstration of PFBC technology for future commercial plants of the 300 MW to 700 MW size. Specifically, the technology is designed to remove 70 to 90 percent of the SO_2, 90 percent of the NO_x and over 99 percent of particulates for an Ohio high-sulphur coal. Site work started in April 1988 and start-up is scheduled for the summer of 1990.

The Tidd PFBC Demonstration Project is the first large-scale PFBC combined-cycle unit in the United States. The project is being co-funded by Ohio Power Company, the U.S. Department of Energy and the Ohio Coal Development Office. The primary goal of the demonstration program is to show that combined cycle PFBC technology is a cost effective, reliable and environmentally superior alternative to conventional coal-fired electric power generation equipped with FGD systems. As part of the program, gas turbine operation and reliability, process performance in removing sulphur oxides and minimizing NO_x production and equipment and system performance and reliability will be demonstrated.[18]

In addition to the Tidd plant, there are two international applications of PFBC technology. Stockholm Energi, the main producer of district heat for the city of Stockholm, will install a PFBC cogeneration plant in the centre of the city for production of electricity and district heating. The plant will go into commercial operation in 1990 using a low-sulphur imported coal. Limestone will be used as the sorbent and the plant will produce 135 MW of electricity and over 220 MW thermal for a total efficiency of 89 percent based on a lower heating value of fuel.[19]

In Spain, ENDESA will repower an existing 62 MW steam turbine at the Escatron plant near Zaragosa with a PFBC unit that will produce 80 MW.

In Canada, B.C. Hydro has carried out detailed studies on the potential application of PFBC for future use of Hat Creek coal.

B.3.4 Future PFBC Development

Pressurized fluidized bed combustion is earlier in the development process than AFBC although it is expected that PFBC will be commercially proven for units entering service after 2000. Pressurized fluidized bed combustion holds promise of higher removal efficiency (95 percent SO_2 removal and 80 to 90 percent NO_x removal) and higher electrical conversion efficiencies than AFBC.

Being based on fluidized bed technology, the PFBC process has the capability of utilizing all coals in an environmentally acceptable manner. It uses a combined cycle for power generation and this provides the step change in efficiency compared to conventional coal combustion techniques. The use of PFBC also means that compact plants can be built, capable of being modularized to a high degree. This in turn makes it possible to clean up existing coal-fired electricity generation sites by means of PFBC retrofits which exhibit the added advantages of increasing power output and efficiency simultaneously.[20]

While the prospects look exciting, some technical problems remain. Some of the difficulties encountered have been: erosion/corrosion of metal surfaces; erosion/corrosion of turbine blades from components of the flue gas; difficulties in cleaning the flue gas stream while retaining available thermal energy in the gas stream (hot gas clean-up); and wastes. Manufacturers now appear to have solved some of these problems; however, work in all of these areas continues.[21]

Work is also proceeding on pressurized, circulating fluidized bed combustion (PCFBC) that is still at the pilot plant stage. Pressurized, circulating fluidized bed combustion is expected to offer the advantages of both pressurization and the better emission control associated with circulating beds.[22]

To prove up PFBC technology, research and development is aimed at:[23]

- in-furnace sulphur capture mechanisms;
- post-furnace reduction of NO_x and SO_2;
- hot acid gas and particulate clean-up before the combustion turbine;
- combustion turbine blade erosion/corrosion;
- control of thermal output; and
- scale-up criteria for units above 200 MW.

As materials become available to design optimal PFBC steam cycles, further energy conversion gains will be realized and environmental performance will improve. The methods being developed to further reduce NO_x emissions consist of modifying in-bed combustion and the use of gas path additive injection. Combustion modification could reduce background emissions to about 70 mg/MJ and gas phase additive injection could then reduce this to about 30 mg/MJ.[24]

Development of hybrid systems, where mild gasification (pyrolysis) is used followed by PFBC for combustion of the residues, offers additional opportunities for improvements in efficiency. The attractiveness of this concept lies in the fact that the thermal efficiency of the pyrolyser/combustor is above 98 percent rather than the 85 to 90 percent typical of pure gasification. Together with advanced steam cycles, net plant efficiencies nearing 50 percent seem possible. Such hybrid systems also enhance the reduction of SO_2 and NO_x--sulphur capture is achieved both during pyrolysis and during the fluidized combustion process and fuel NO_x formation can potentially be decoupled from temperature and controlled by excess air alone.[25]

B.4 Integrated Gasification Combined Cycle

Many clean coal technologies under development promise to reduce emissions of SO_2 and NO_x to a fraction of their uncontrolled levels. However, most of these technologies control only one emission and often complicate boiler operations. In addition, many of these technologies also result in a reduction in the overall efficiency of power generation which effectively results in an increase in emissions of carbon dioxide.[26]

An exception, gaining widespread interest by electric utilities around the world, is IGCC--the combination of coal gasification and the combined-cycle generation of electricity. Integrated gasification combined cycle reduces acid gas emissions significantly and also reduces CO_2 emissions by virtue of the increased efficiency of combined cycle electricity generation. All of these benefits accrue at a projected cost similar to that of conventional coal-fired power plants fitted with equivalent environmental capability.

While there is only limited experience with IGCC, there is substantial experience with the individual components of the system: combustion turbine units, combined cycle electricity generation and gasification of coal.

- Coal gasification has been in use for at least 100 years and several coal gasification plants producing syngas for chemicals have been in operation in South Africa, Turkey, India and other countries since the mid-1950s.

- Gas clean-up technology is very similar to that which has been in use for many years in the natural gas industry.

- Combustion turbines have in recent years been developed up to the 150 MW range and have an excellent record of reliability.

- The use of combined-cycle generation is now accepted as a cost-effective power generation technology in the U.S. electrical utility industry.

- Integrated gasification combined cycle demonstration projects have been built in the United States, one is presently being built in the Netherlands and others are proposed in Europe, Japan and Canada.

B.4.1 IGCC Process Description

Integrated gasification combined cycle involves the contacting of coal, oxygen or air, and in some cases steam, in a reactor (e.g., fixed bed, fluidized bed or entrained flow) at elevated temperatures and pressures to produce synthesis gas. The ash, which does not gasify, is easily separated as a glassy, inert material (slag) which can be landfilled or used as a construction material. The synthesis gas (syngas) is a mixture of predominantly hydrogen and carbon monoxide with an energy content approximately one third that of natural gas.[27]

Before the syngas is used in the generation of electricity, it is first processed to remove acidic and particulate components. These cleaning steps require that the gas be cooled in order that they be effective. Particulates are removed through a water saturation method which effectively separates out particulate matter. Sulphur is removed using solvents commercially proven in refinery and natural gas production applications. The effectiveness of this solvent system is largely responsible for low sulphur emissions associated with gasification-based power plants.

After removal of the particulates and sulphur from the gas stream, the synthesis gas is then used in conventional gas turbines to produce electricity. As a NO_x control method, the gas is normally saturated with water or steam prior to combustion. Additional electricity is produced by capturing the waste heat from the gas turbine exhaust gases which are passed through a heat recovery boiler to raise steam and to generate electricity in a steam turbine.[28]

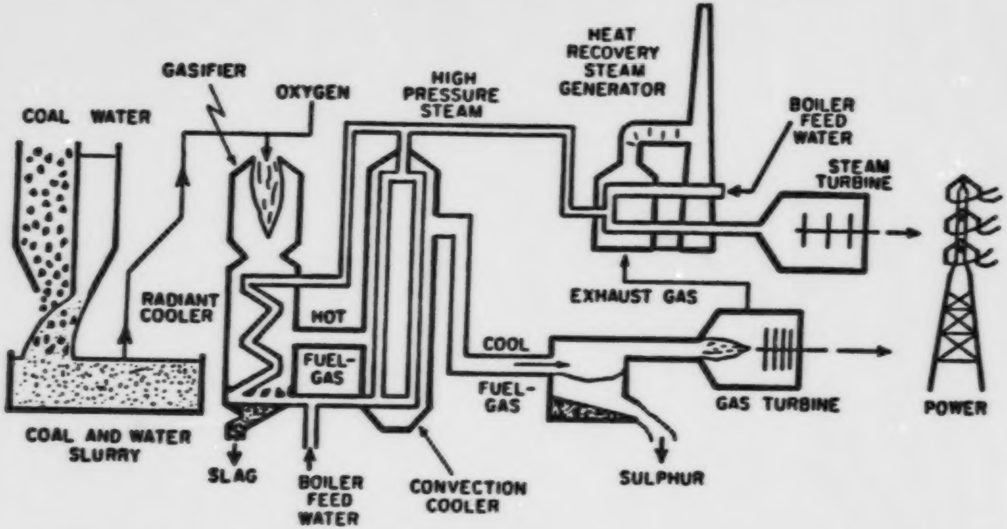
Figure B.3 depicts an IGCC configuration showing the various steps involved in gasifying and cleaning the syngas, and producing electricity in a combined cycle configuration.

B.4.2 IGCC Attributes

The general characteristics of an IGCC system can be summarized as:

- Feedstock
    - There are no special coal handling requirements other than the possibility of adding limestone to the coal feed to capture a portion of the sulphur emissions inside the gasifier.
    - Integrated gasification combined cycle plants can be designed to gasify alternative, low cost feedstocks (e.g., coke and sewage sludge) and produce high value by-products from syngas such as methanol and octane enhancers and CO_2 for use in enhanced oil recovery.[29]
- Application
    - Combined cycle plants can be made up of standardized modules in 100 to 200 MW sizes which considerably reduces work carried out at the plant site and the time needed to construct the plant. This enhances planning flexibility and savings in total project cost through lower interest charges.[30]
    - Integrated gasification combined cycle is expected to find primary application in new facilities, although repowering of older electrical generating plants is also feasible.
- Waste
    - As gasification is generally carried out at high temperatures, the ash in the coal is melted to a slag. The molten slag is cooled and separated and is discharged from the gasifier as a glassy, inert and non-leachable material which can be landfilled or used as a construction material.[31]
    - The gasification plant recovers sulphur as a saleable by-product which reduces landfill requirements by about two-thirds compared to conventional coal-fired plants fitted with FGD systems.
- Land/Water Use
    - Integrated gasification combined cycle cooling water requirements are about one-third those required for a

Figure B.3
Integrated Coal Gasification Combined Cycle System


GASIFIER
OXYGEN
HIGH PRESSURE STEAM
HEAT RECOVERY STEAM GENERATOR
BOILER FEED WATER
STEAM TURBINE
COAL
WATER
RADIANT COOLER
HOT
FUEL-GAS
COOL
FUEL-GAS
EXHAUST GAS
GAS TURBINE
POWER
COAL AND WATER SLURRY
SLAG
BOILER FEED WATER
CONVECTION COOLER
SULPHUR

SOURCE: G.K. Lee, Canadian Coals, "The Environment and New Coal Technologies," Presentation to the Canadian Energy Research Institute's *Energy and Electricity: A Conference on Electric Power Planning in the 1990s*, Montreal, Quebec, June 3-5, 1990.

conventional coal-fired power plant, as a large proportion of the electricity generated by an IGCC plant is produced by gas turbines which do not require water cooling as steam turbine condensors do.[32]

- Integrated gasification combined cycle land area requirements are considerably less than those for conventional coal-fired plants with equivalent emissions.

- Efficiency/Emissions
  - Integrated gasification combined cycle has the potential to increase efficiency from coal-fired plants from 36 to 38 to near 45 percent while reducing NO_x by 90 percent and SO_2 by 99 percent. As shown in Table B.4, these modest increases in efficiency result in large reductions in the production of CO_2 (e.g., 5 percent increase in efficiency reduces CO_2 emissions by about 15 percent).
  - By using a water shift reaction to convert carbon monoxide in the fuel gas to CO_2 and hydrogen, IGCC technology also offers the potential for economic recovery of CO_2 for use in such applications as enhanced oil recovery.[33]
  - Further reductions in plant emissions and liquid discharges are possible. NO_x can be reduced by advanced gas turbine combustor designs and/or selective catalytic reduction. Sulphur dioxide can be virtually eliminated at a moderate cost and the plant can also be designed for zero discharge of process waste water.[34]
  - It is highly unlikely that any heavy metals or chlorides will escape being scrubbed out of the gas phase prior to combustion in the gas turbine, owing to the number of stages of high pressure liquid "scrubbing" conducted in a coal gasification facility.

- Costs
  - Integrated gasification combined cycle is cost competitive when compared to a conventional coal-fired unit fitted with SO_2 and NO_x controls.
  - Capital costs of IGCC are about \$1700-\$2100/kW compared with \$1200-\$1400/kW for a conventional coal-fired thermal power plant with no sulphur-removing FGD's. Flue gas desulphurization would raise capital costs to \$1350-\$1700/kW. These additional costs cover the reduction in SO_2 but as not account for any reductions, and associated costs in reducing, NO_x and CO_2 emissions. As noted earlier, NO_x reduction by SCR would add in the order of \$2000-\$4000/tonne.[35]

TABLE B.4

TECHNOLOGIES WHICH IMPROVE COAL COMBUSTION AND EMISSIONS
(%)

Type	Technology	Ash Removal	SO_2 Removal	NO_x Removal	Efficiency	CO_2 Removal
Pre-Combustion[a]	Blending	-	40-45	-	-	-
	Selective Agglomeration & Advanced Froth Floation	-	50-70	-	-	-
	Advanced Coal Cleaning	-	30-90	-	Slight Increase	-
Combustion	Coal-Fired	Base	Base	Base	36-38	Base
	Low NO_x/SO_x Burner	80	90+	50-60	38	N/A
	Atmospheric FBC	99.5	85-90	40-50	37	Increase
	Pressurized FBC	99.9	90-95	70	40	16+
	IGCC	99.9	99	90	34-52	16+
	IGCC/Fuel Cells	99.99	99	95	55	51
	Topping Cycle	99.99	95	90	45	N/A
	Magnetohydrodynamics with Fuel Cells	N/A	N/A	N/A	66.7	87
	Combined Heat & Power (CHP)	N/A	N/A	N/A	70-80	54
	Energy Cascading	90+	85-99	50-95	40-80	10-70
	Sorbent Injection	N/A	≤50	N/A	36-38	Base
Post-Combustion	Coal-Fired with FGD	99.5	20-90	-	37	Base
	Coal-Fired with FGD & SCR	99.5	20-90	90+	36	Base
	Sorbent Injection - LIFAC	N/A	90	N/A	36-38	Base
	Duct Injection	N/A	50-70	N/A	36-38	Base

SOURCE: Coal Association of Canada, *Brief on Global Warming to the House of Commons Standing Committee on Environment* (Calgary, Alberta: Coal Association of Canada, December 14, 1989), pp. 5-6 and 5-7.

[a] Only applicable to a limited range of coals.

B.4.3 IGCC Application

One of the most important and unique characteristics of the IGCC concept is the flexibility this technology provides utility planners in dealing with the uncertainties associated with forecasting and planning for future load growth coupled with uncertain future fuel prices. This flexibility stems from the ability to install the full IGCC facility in a series of steps or phases.

In the first phase, a natural gas-fired turbine with no heat recovery is installed. This allows peaking capacity to be added quickly as gas turbines have lead times in the order of two to three years. It also enables a utility to match load growth very closely by adding units in roughly 100 MW increments. In the second phase, a waste heat boiler and steam turbine system would be installed to complete the combined cycle component of the plant, allowing higher efficiency and the upgrading of the facility to base load or cycling load generation. Installation of the coal gasification plant would complete the IGCC facility but this stage can be left until natural gas prices rise sufficiently to make addition of this phase economic.

Integrated gasification combined cycle's ability to respond quickly to changes in electricity demand with relatively small increments of generating capacity is extremely important, as it enhances planning flexibility by reducing the risk of errors in forecasting future electricity demand. In the past, use of "conventional" technologies involving large blocks of capacity and long lead times added significantly to costs, as plants were sometimes brought on stream in times of slackening electricity demand. In addition, the relatively low capital cost of gas turbines reduces the total investment at risk, as the major cost of the coal gasification plant can be delayed until warranted.

While IGCC technology is best suited to new power plant applications, it may also be used to repower existing gas, oil or coal-fired boilers. The benefits of repowering existing facilities are lower capital costs and shorter lead times due to fewer licensing requirements for existing sites. An existing plant, at the end of its useful life, can be repowered to have the thirty-year lifetime of a new facility. Moreover, the repowered IGCC plant would significantly improve electrical generation efficiency and environmental performance, especially in limiting SO_2, NO_x and CO_2 emissions.[36]

Integrated gasification combined cycle also affords a unique opportunity for producing valuable by-products from the gasification of coal, when electricity production is naturally scaled back at night to match low demand periods.

> In an IGCC plant, the capacity factor on the costly gasification section of the plant could be significantly increased if the syngas that could be produced when the power plant was not operating could be converted into a valuable chemical by-product for sale. This idea of co-producing a number of products at a single facility, leads to the concept of an integrated energy facility (see Figure B.4). It has been shown that the synergism provided by the co-production of electric power and chemicals in a facility of this type could potentially result in reductions in the cost of producing electricity that are as high as 33 percent. This type of operation (an opportunity unique to coal gasification) not only increases the value added to both capital equipment and fuel, but also provides a long term opportunity for diversification and the generation of low cost electric power, significantly increasing the ability of the electric industry to be competitive.[37]

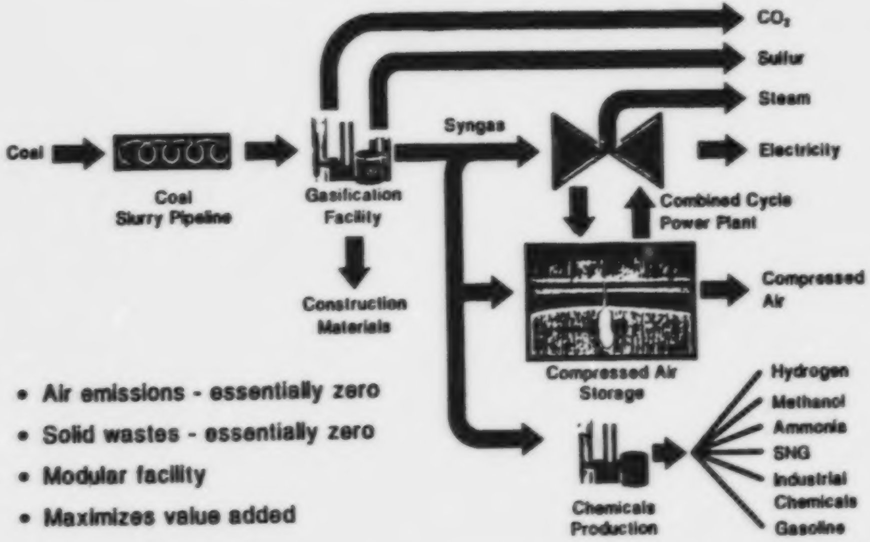
B.4.4 Operating Experience

While there are currently no fully integrated commercial IGCC plants in operation, a number are planned for the early 1990s.

In 1977, Texaco, Southern California Edison, the Electric Power Research Institute, General Electric, Bechtel and a consortium known collectively as the Japan Cool Water Partnership began the development of the first full scale IGCC commercial demonstration project--the Cool Water facility in Daggett, California. During its five year operating period (1984-1989), Cool Water reached and surpassed all goals set for its operation. Cool Water was designed to gasify 1000 tons per day of coal to produce 100 MW of electrical power. One of this plant's most noted accomplishments was its environmental performance. The Cool Water plant attained very high levels of NO_x and SO_2 removal, 90 and 99 percent, respectively. Slag produced by Cool Water was shown to be nonhazardous and as little as a third of the volume produced with other coal-based power systems (see Figure B.5).[38]

In 1989, the Cool Water program ended its scheduled five-year operating phase, having established the viability of IGCC technology. At the conclusion of the program, Texaco purchased the Cool Water plant and it intends to have it up and operational again in 1992,

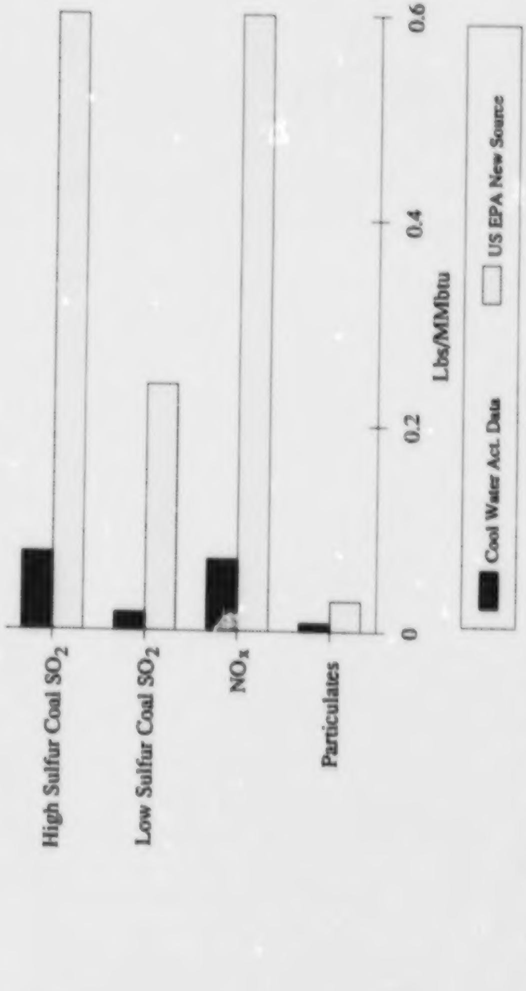
Figure B.4
Integrated Energy Facilities


Coal
Coal
Slurry Pipeline
Gasification
Facility
Construction
Materials
Syngas
CO_2
Sulfur
Steam
Electricity
Combined Cycle
Power Plant
Compressed
Air
Compressed Air
Storage
Chemicals
Production
Hydrogen
Methanol
Ammonia
SNG
Industrial
Chemicals
Gasoline

- Air emissions - essentially zero
- Solid wastes - essentially zero
- Modular facility
- Maximizes value added

SOURCE: Michael Gluckman, "Status and Outlook for IGCC," Canadian Electrical Association, Canadian Perspectives for IGCC, Montreal, Quebec, March 29-30, 1990.

Figure B.5
Cool Water Plant



SOURCE: Paul F. Curran, Perspectives for IGCC, Montreal, March 29-30, 1990.

producing electricity from a mixture of 75 percent coal and 25 percent sewage sludge from nearby Los Angeles. Texaco notes that gasification of other waste materials is also possible.

> Due to the high temperatures at which coal gasifiers operate, materials such as contaminated soils, waste oils, and refinery wastes can be disposed of in a fashion which is environmentally superior to any other commercially available method. One of the best examples of Texaco gasification which may capitalize upon this feedstock flexibility is the Delaware Clean Energy Project located at Star Enterprise's Delaware City petroleum refinery.[39]
>
> The project will use petroleum coke produced at the refinery as a feedstock. Approximately 20,000 tons of petroleum coke per day will be converted into synthesis gas which will be burned to make steam and electricity. Plant operations are scheduled for the mid-1990s.[40]

Internationally, active interest in IGCC has been shown by both electric utilities and chemical industries. The first commercial IGCC unit to come on-line in Europe will be based on the Shell Gasification process and is scheduled for completion in 1993 at Buggenum, Holland. A single gasification train designed for approximately 2000 tonnes/day of imported coal will feed a single shaft Siemens gas turbine to generate 250 MW of electricity with an efficiency of 41.4 percent Higher Heating Value (HHV). An interesting facet of this IGCC design is zero water discharge from the gasification island. Process effluent will be evaporated, with the condensate being used as a source of boiler feed water. Following a three-year demonstration period, during which different coals and operating conditions will be tested, the unit will be used to provide base-load power. Germany is also planning to have a 150 MW IGCC unit with 45 percent efficiency in commercial operation by 1994.[41]

The success of the Cool Water demonstration plant in California has also sponsored widespread interest in Canada--many utilities believe that IGCC is the generation technology for the 1990s. Integrated gasification combined cycle technology is under active consideration in New Brunswick, Ontario, Nova Scotia, Saskatchewan and Alberta.

A major evaluation of IGCC for three sites in Canada--Nova Scotia, Ontario and Alberta--was recently completed by Bechtel Canada Inc.. The work was sponsored by the Canadian Electrical Association and was funded by the Government of Ontario, Ontario

Hydro, Environment Canada, and members of the Canadian Coal Gasification Technical Committee. Conceptual engineering design, plant performance, the selection of gasification processes, emission projections and capital cost estimation were carried out as part of the work undertaken by Bechtel.[42]

In addition, recognition of growing public concern over coal's impact on the environment and the need for IGCC demonstration under conditions unique to Canada, encouraged the Coal Association of Canada (CAC) to propose the design, construction, and operation of an IGCC demonstration project. The proposed study will address CO_2 removal, environmental emissions, site selection, process selection and capital and operating costs. This will result in a project description and cost estimate of sufficient detail to evaluate the economics of IGCC in specified Canadian applications.

One of the unique facets of the Coal Association's proposed IGCC study is the assessment of carbon dioxide recovery and disposal. It is anticipated that over 50 percent of the CO_2 could be removed after a water shift reaction converts carbon monoxide to CO_2. As a result, carbon dioxide emissions would be approximately the same as those resulting from the combustion of natural gas. The CAC contends that CO_2 production from a significant percentage of the presently installed coal-fired generation in western Canada could be used for enhanced oil production. However, other means of disposing of CO_2, including injection into salt domes or depleted oil and gas reservoirs or into brines or other aquifers, would also be assessed as part of this research.

The province of Saskatchewan is also supporting joint government-industry assessment of the technical and economic feasibility of using IGCC for post-2000 power generation. Saskatchewan is currently considering the testing of a lignite coal in a pilot gasification unit to determine the gasification characteristics of the coal.

B.4.5 Future Efficiency Potential

As IGCC technology is still very much at the beginning of its development cycle, significant reductions in costs and improvements in performance are expected as experience is gained in demonstration of the concept. While gas combined-cycle technology is, for example, a relatively recent addition to power utility options, improvements in gas turbine technology have significantly boosted combined-cycle efficiencies over those possible in the conventional steam cycle coal-fired power plant. These improvements have occurred primarily through increases in the gas turbine firing temperatures. Technical improvements are now being demonstrated in the lab and at pilot plant scale that show even better possibilities for the 1990s.

The major areas of research and demonstration are in combustion turbines (advanced higher temperature designs), gas clean-up (development of hot gas clean-up, thus increasing cycle efficiency and reducing losses), air separation technology (integration with the gas turbine cycle), and improvements in efficiency and energy use.

Current sulphur removal processes require that the hot gas exiting the gasifier be cooled prior to sulphur removal. The gas is then reheated before gas-turbine firing to improve turbine efficiency. Cooling the gas requires rather expensive heat exchangers and also introduces a cycle efficiency penalty. Current research efforts are aimed at developing hot gas clean-up designs where the gas exiting the gasifiers is scrubbed of sulphur and other contaminants at or near gasifier temperatures , followed by direct combustion in the gas turbine. A Bechtel in-house study predicts that hot gas clean-up may improve overall heat rate by about 5 percent and reduce capital cost by as much as 20 percent.[43]

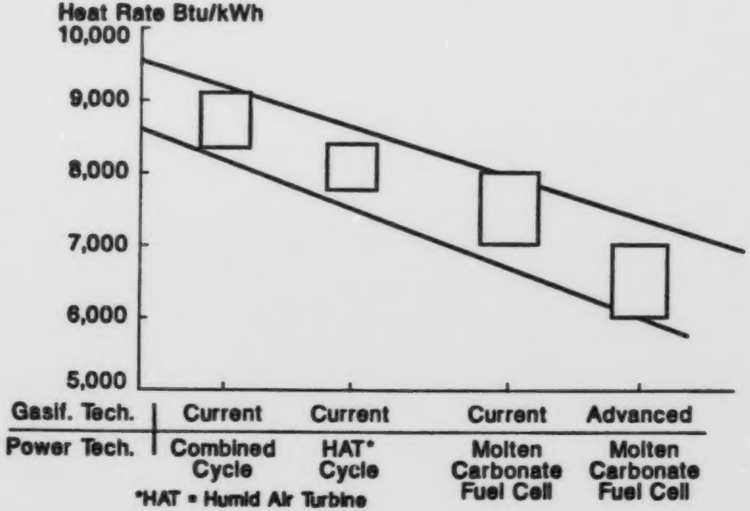
One version of the hot gas clean-up process uses gasification with air and hot gas clean-up to eliminate heat exchangers and improve efficiency by feeding the fuel directly to the gas turbine. Another improvement under investigation for second generation plants is the integration of the gas turbine and the air separation plant. These improvements could push IGCC technology to 46 percent Lower Heating Value (LHV) efficiency, giving a 20 percent reduction in coal use for future coal plants.[44]

Complimentary to hot gas clean-up is ongoing research aimed at developing gas turbines which can operate at higher gas inlet temperatures. For example, gas turbine manufacturers are developing ceramic block materials which would allow higher inlet temperatures and combined cycle efficiencies of 60 percent (LHV). This would reduce fuel requirements by up to 15 percent and reduce plant capital charges by $100-$200 per kW.[45]

Various other synergies are also being explored. At the University of North Dakota, tests are being done to assess

Figure B.6

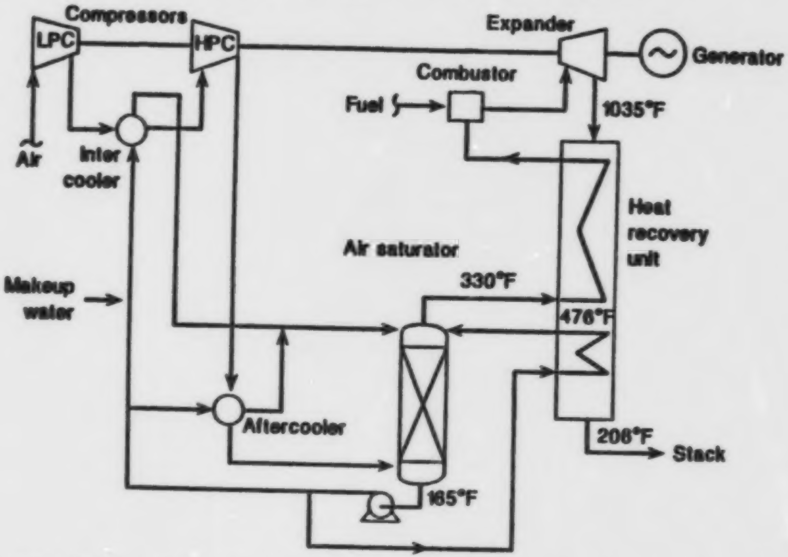
Efficiency Improvements for Gasification-Based Power Plants



SOURCE: Michael Gluckman, "Status and Outlook for IGCC," Canadian Perspectives for IGCC, Montreal, Quebec, Canadian Electrical Association, March 29-30, 1990.

Figure B.7

Hat Cycle - Simplified Flow Diagram


Compressors
LPC
HPC
Expander
Generator
Combustor
Fuel
1035°F
Air
Inter cooler
Heat recovery unit
Air saturator
330°F
Makeup water
476°F
Aftercooler
208°F
Stack
165°F

SOURCE: Michael Gluckman, "Status and Outlook for IGCC," Canadian Perspectives for IGCC, Montreal, Quebec, Canadian Electrical Association, March 29-30, 1990.

cogeneration with IGCC and fuel cells. The waste heat from the fuel cell is recycled to the gas turbine to increase the efficiency of the system--efficiencies of up to 60 percent are expected.[46]

Figure B.6 shows potential efficiency improvements for coal gasification-based power plants showing a development path from the current system efficiency estimates of 38 percent to efficiencies as high as 56 percent.

> No other coal-based technology has anything like this potential. An illustrative example of the efficiency potential exhibited by gasification-based power systems is the IGHAT cycle (integrated gasification humid air turbine). This system utilizes low level waste heat to humidify the combustion air in the regenerative turbine system (see Figure B.7). A recent study by the Electric Power Research Institute (EPRI), Fluor Daniel and a consortium of utilities of this cycle has shown that heat rates as low as 8100 Btu per kW.h are attainable using the HAT turbine in conjunction with a quench Texaco gasifier at an estimated $300 per kW reduction in capital cost over a conventional IGCC plant. In the IGHAT plant studied, 98 percent of the sulphur in the coal would be removed and projected nitrogen oxide emissions would be in the range of 5 ppm to 7 ppm.[47]

Footnotes

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[2] U.S. Congress Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s* (Washington, D.C.: U.S. Government Printing Office, July 1985), p. 113.

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[4] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) in Canada:* Work Sub-Group 6.2 Report, Stationary Sources - NOx (Ottawa, Ontario: Environment Canada, January 1990), p. 35.

[5] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effect of Acid Deposition," Vol. II - Emissions and Controls (Washington, D.C.: National Acid Precipitation Assessment Program, 1987), p. 2-33.

[6] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) in Canada*, 1990, pp. 35-36.

[7] Ibid., pp. 35-36.

[8] Ibid., pp. 35-36.

[9] Ontario Hydro, *Thermal Cost Review*, Vol. I (Toronto, Ontario: Ontario Hydro, October 1989), pp. 63-64.

[10] United States, Acid Precipitation Assessment Program, "Interim Assessment - The Causes and Effects of Acid Deposition," 1987, pp. 2-39 to 2-41.

[11] Environment Canada, *Control Technologies for Management of Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) in Canada*, 1990, pp. 35-36.

[12] Ontario Hydro, *Thermal Cost Review*, 1989, pp. 26-27.

[13] Krishna K. Pillai, "Commercial Status and Further Development of PFBC" in *EPRI Proceedings 1989 Conference on Technologies for Producing Electricity in the Twenty-First Century*, San Francisco, California, October 30-November 2, 1989, p. 5.

[14] Ibid., p. 5.

[15] Ibid., p. 6.

[16] Environment Canada, *Control Technologies for Management of Nitrogen Oxides* (*NO_x*) *and Volatile Organic Compounds (VOC) in Canada*, 1990, pp. 37-38.

[17] International Energy Agency, *The Clean Use of Coal: A Technology Review* (Paris, France, Organisation for Economic Co-Operation and Development, 1985), p. 84.

[18] Krishna K. Pillai, "Commercial Status and Further Development of PFBC," p. 8.

[19] Ibid., p. 7.

[20] Ibid., p. 12.

[21] International Energy Agency, *Emissions Controls in Electricity Generation and Industry*, 1988, pp. 74-75.

[22] Ibid., p. 74.

[23] Environment Canada, *Control Technologies for Management of Nitrogen Oxides* (*NO_x*) *and Volatile Organic Compounds (VOC) in Canada*, 1990, pp. 37-38.

[24] Krishna K. Pillai, "Commercial Status and Further Development of PFBC," 1989, p. 11.

[25] Ibid., p. 12.

[26] See McDonald, M., "Canadian Initiatives in IGCC Technology," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[27] Paul F. Curran, "Texaco Coal Gasification - Status and Developments," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[28] Robert F. Geosits and Lee A. Schmoe, "Evaluation of IGCC for Canadian Utility Applications," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[29] M. M. McDonald and Dr. J. B. Railton, "The Coal Association of Canada's IGCC Project," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[30] Ibid.

[31] Ontario Hydro, *Providing the Balance of Power* (Toronto, Ontario: Ontario Hydro, January 31, 1989), pp. 5-3.

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[33] M. M. McDonald and Dr. J. B. Railton, "The Coal Association of Canada's IGCC Project," 1990.

[34] Coal Association of Canada, *Brief on Global Warming to the House of Commons Standing Committee on Environment* (Calgary, Alberta: Coal Association of Canada, December 14, 1989), pp. 5-1 to 5-2.

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[38] Paul F. Curran, "Texaco Coal Gasification - Status and Developments," 1990.

[39] Richard J. Payonk, "Tomorrows Energy Today - The Advanced DESTEC Coal Gasification Process," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[40] Paul F. Curran, "Texaco Coal Gasification - Status and Developments," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

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[42] M. M. McDonald and Dr. J. B. Railton, "The Coal Association of Canada's IGCC Project," 1990.

[43] J. C. Selover, Jimmie R. Bowden and Jon Pietruszkiewicz, "Overview of Commercial Gasification Projects, in *Energy Technology XV* (Rockville, Maryland: Government Institutes, Inc., February 1988), p. 233.

[44] Douglas M. Todd, "Advanced Gas Turbine/Combined Cycle for IGCC," presented at *Canadian Perspectives for IGCC*, Canadian Electrical Association, Montreal, Quebec, March 29-30, 1990.

[45] Bechtel Canada Inc., *Evaluation of Integrated Coal Gasification Combined Cycle for Canadian Utility Applications* (Montreal, Quebec: Canadian Electrical Association, September 15, 1989).

[46] Coal Association of Canada, *Brief on Global Warming to the House of Commons Standing Committee on Environment*, 1989, pp. 5-2.

[47] Michael Gluckman, "Status and Outlook for IGCC," 1990.

APPENDIX C

CANADIAN ELECTRICAL GENERATING PLANNING MODEL (ELGEM) - VERSION 2.0

Appendix C

CANADIAN ELECTRICAL GENERATING PLANNING MODEL (ELGEM) - VERSION 2.0

C.1 Background

The planning environment for the Canadian electric industry is undergoing fundamental change. In the 1990s, issues such as environmental protection, electricity trade, demand-side management and non-utility generation will become more relevant in capacity planning. All these will have important political, economic and social implications for Canada's electricity industry. In response to these, the Canadian Energy Research Institute (CERI) undertook a research study of *Critical Issues in Electric Power Planning in the 1990s*. In view of the complicated and interrelated aspects of many of the factors affecting future demand and supply of electric power, a comprehensive, analytical framework was deemed necessary. A model (ELGEM) was developed by the Alberta Research Council for the Canadian Energy Research Institute to provide a broad assessment of the future trends in Canadian electric power generation, transmission and trade.

Considerable refinement and enhancements to the original model are contained in Version 2.0 of ELGEM, for use by CERI in the assessment of the role of new coal technologies in meeting Canada's environmental goals in the electric power sector.

C.2 Model Description

ELGEM is a linear programming, optimizing, long-term electricity generation supply model for Canada and the United States.

The Canadian electric power industry is divided into eight regions, with the Atlantic Provinces treated as one region and the other provinces treated as individual regions. To capture the potential for enhanced international transfers of electricity, the United States is represented as four distinct market regions, in which Canadian power can compete.

The electric generating technologies, including hydro, nuclear, coal, gas turbine, gas-fired combined cycle etc., are modelled in detail. Long distance transmission lines which link supplies to demand centers are an important part of the supply chain, and are also modelled. The supply options are described in terms of their capital investment schedules, operating characteristics, costs, and emission profiles. The regional aspects of the supply options are captured in the model. A simplified schematic for ELGEM for one region is shown in Figure C.1.

In Version 2.0 of ELGEM, the costs of electric generating technologies (e.g., atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC)) and their air emission factors have been added with the most recent data from the Canadian electric utilities, the Canadian Electrical Association (CEA), the Electric Power Research Institute (EPRI), and the technology developers. Other improvements made to ELGEM include the incorporation of emission control technologies into the modelling framework. This enhancement allows ELGEM to assess how emission control policies in Canada would impact on the electric power sector.

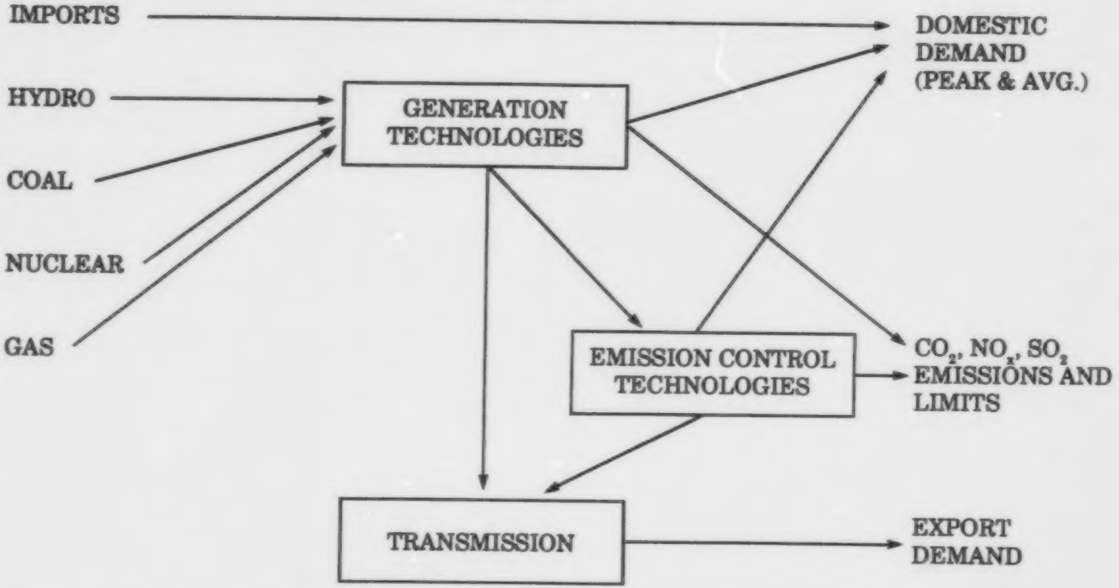
Currently, three levels of emission control ranging from 30 to 80 percent reductions for each of nitrogen oxide (NO_x) and sulphur dioxide (SO_2) have been incorporated, reflecting a range of cost and technology options. These technologies include low excess air, overfire air, low NO_x burner, selective catalytic reduction, flue gas desulphurization, gas reburn, and sorbent injection. Generic technology costs have been considered; however, these costs may vary for specific retrofit applications at some plant locations. Carbon dioxide (CO_2) is not controlled in this version, as there are no economically viable options for reducing post-combustion CO_2 emissions. However, regional CO_2 emissions in Canada are reported to assess the emissions impact of changes in energy efficiency under the various scenarios.

Electric power demand by region forms part of the input data; hence it is exogenous to the model. For the demand to be satisfied, two conditions must be met:

(1) there must be enough dependable capacity to meet the forecast average load; and

(2) there must be enough peak capacity to meet the forecast peak power requirements, plus a specified reserve margin.

Figure C.1
ELGEM


IMPORTS
HYDRO
COAL
NUCLEAR
GAS
GENERATION TECHNOLOGIES
EMISSION CONTROL TECHNOLOGIES
TRANSMISSION
DOMESTIC DEMAND (PEAK & AVG.)
CO_2, NO_x, SO_2 EMISSIONS AND LIMITS
EXPORT DEMAND

SOURCE: Alberta Research Council.

For the period 1988-2010, given a demand forecast and the availability and costs of all perceived electric generating options, ELGEM generates a capacity addition schedule that minimizes the present value of the costs. In this respect, the model follows the methodology of Rogers and Choudhury (University of Toronto, 1977) rather than the decision rule, year-by-year approach employed in some other models (e.g., National Energy Board's UGENEX Model).

The model has perfect foresight and therefore, given the conditions specified in the scenario, the results represent an upper limit of what can be achieved.

The model is written in a user-friendly language called MAGEN, developed by Haverley Systems Inc.

C.3 Model Capabilities

The model can be used to assess the impact of a wide variety of alternative scenarios. Among the scenarios that can be evaluated using ELGEM are:

(1) Selection of both Canadian and U.S. discount rates for generation and transmission technologies, to permit the investigation of public and private sector financing options.

(2) Modification of demand growth rates by region, in order to investigate demand management options.

(3) Impact of environmental regulations (CO_2, SO_x, NO_x) on the future electric generating mix and the cost/benefit of the various abatement options.

(4) Assessment and impact of technological developments, such as new clean coal technologies.

(5) Restrictions on the development of certain supply technologies, i.e., no nuclear plants in the U.S. to the end of the century; fixing the mix of nuclear/coal generation in Ontario.

(6) Policy restrictions on inter-provincial and international transfer of power.

ELGEM is one of a number of energy models developed by the Albert Research Council, including the AERAM family of hydrocarbon development models.

The Alberta Research Council is prepared to tailor these models for assessment of third-party scenarios, on a fee-for-service basis. Interested parties are encouraged to contact the Alberta Research Council for further information on ELGEM and to discuss application of this framework for specific issues of interest to them.

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APPENDIX D

SUPPORTING INFORMATION FOR GENERATING SCENARIOS AND DETAILED MODEL OUTPUT

TABLE D.1

COST AND EMISSION COEFFICIENTS OF SOME CLEAN COAL TECHNOLOGIES

	Capital Cost ($/kW)[a]	Efficiency (percent)	Emission Coefficients		
			CO_2	SO_2	NO_x
			(g/kW.h)		
Alberta					
Conventional[b]	1249	35.9	951	4.24	3.03
IGCC	1600	37.6	913	0.51	0.46
FGD	300	90.0			
Ontario					
Conventional[c]	1507	34.9	890	1.60	0.28
IGCC	1655	38.5	806	0.32	0.45
AFBC	2014	35.2	928	1.74	1.12
PFBC	1960	35.2	927	0.72	0.72
FGD	250	90.0			
SCR	148	80.0			
New Brunswick, Nova Scotia, and Prince Edward Island					
IGCC	1883	38.2	805	0.46	0.46
AFBC	2014	35.2	946	2.04	1.38
PFBC	1960	35.2	946	0.72	0.72
FGD	300	90.0			
LNG	10	30.0			
SCR	178	80.0			

SOURCES: Alberta Research Council and Canadian Energy Research Institute

[a] Not including Interest During Construction.
[b] No FGD or SCR.
[c] Including FGD and SCR.

D.2 BASE CASE

TABLE D.2a

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN BRITISH COLUMBIA
(gigawatts)

	1988	2000	2009
Existing Hydro	10.85	11.92	12.47
Existing Gas Fired	0.90	0.90	0.90
Existing Combustion Turbine	0.17	0.31	0.31
New Hydro - Site 1		0.40	2.44
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine		0.67	0.93

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2b

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN ALBERTA
(gigawatts)

	1988	2000	2009
Existing Hydro	0.73	0.73	0.73
Existing Pulverized Coal (Low Sulphur)	4.87	6.16	6.16
Existing Gas Fired	1.40	1.40	1.40
Existing Combustion Turbine	0.57	0.57	0.57
New Hydro - Site 1			
New Pulverized Coal (Low Sulphur)		1.90	4.30
New Combustion Turbine		0.11	0.27

SOURCES: Alberta Research Council and Candian Energy Research Institute

TABLE D.2c

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN SASKATCHEWAN
(gigawatts)

	1988	2000	2009
Existing Hydro	0.84	0.84	0.84
Existing Pulverized Coal (Low Sulphur)	1.53	1.83	1.83
Existing Gas Fired	0.27	0.27	0.27
Existing Combustion Turbine	0.16	0.16	0.16
New Pulverized Coal (Low Sulphur)			0.15
New Combustion Turbine		0.55	0.81

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2d

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN MANITOBA
(gigawatts)

	1988	2000	2009
Existing Hydro	3.64	5.04	5.04
Existing Pulverized Coal (Low Sulphur)	0.37	0.37	0.37
Existing Combustion Turbine	0.06	0.06	0.06
New Hydro - Site 1			0.09
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine	0.41	1.35	3.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2e

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN ONTARIO
(gigawatts)

	1988	2000	2009
Existing Hydro	7.81	7.81	7.81
Existing Pulverized Coal (High Sulphur)	10.65	10.65	10.65
Existing Gas Fired	0.45	0.45	0.45
Existing Combustion Turbine	0.63	0.63	0.63
Existing Nuclear	10.64	14.16	14.16
Existing Oil Fired	2.53	2.53	2.53
New Hydro - Site 1			1.20
New Pulverized Coal (High Sulphur)			
New Nuclear			
New Comubstion Turbine			
New IGCC		4.03	8.12

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2f

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN QUEBEC
(gigawatts)

	1988	2000	2009
Existing Hydro	31.40	32.46	32.46
Existing Nuclear	0.69	0.69	0.69
Existing Combustion Turbine	0.36	0.36	0.36
Existing Oil Fired	0.48	0.48	0.48
New Hydro - Site 1		4.74	7.20
New Hydro - Site 2		6.39	8.70
New Hydro - Site 3			1.80
New Hydro - Site 4			0.75
New Hydro - Site 5			
New Nuclear			
New Combustion Turbine		1.79	1.79

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2g

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND
(gigawatts)

	1988	2000	2009
Existing Hydro	1.28	1.28	1.28
Existing Pulverized Coal (High Sulphur)	1.48	1.78	1.78
Existing OF	1.96	1.96	1.96
Existing Nuclear	0.64	0.64	0.64
Existing Combustion Turbine	0.28	0.28	0.28
New Nuclear			
New Pulverized Coal (High Sulphur)			
New Combustion Turbine		1.14	1.58
New IGCC		1.12	2.64

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2h

SCENARIO: BASE CASE
MIX OF GENERATING TECHNOLOGIES IN LABRADOR AND NEWFOUNDLAND
(gigawatts)

	1988	2000	2009
Existing Hydro	1.24	1.24	1.24
Existing OF	0.51	0.51	0.51
Existing Combustion Turbine	0.25	0.25	0.25
New Hydro - Site 1		0.35	2.32
New Combustion Turbine	0.12	2.97	2.97

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2i

SCENARIO: BASE CASE
REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--CARBON DIOXIDE
(millions of tonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	2.9	35.0	8.4	3.0	29.7	0.0	11.7	2.6	93.2
1991	2.9	42.4	11.2	0.0	29.7	0.0	16.2	2.6	105.0
1994	2.9	47.8	12.7	0.0	25.9	0.0	19.2	2.6	111.0
1997	2.9	32.5	13.9	4.2	32.5	0.0	21.7	2.6	130.2
2000	2.9	57.0	16.0	8.8	37.5	0.0	24.2	2.6	148.9
2003	2.9	61.2	15.9	13.2	33.2	0.0	26.5	2.6	155.5
2006	2.9	65.9	16.8	14.5	46.2	0.0	29.0	2.6	177.7
2009	2.9	71.1	17.5	15.0	54.0	0.0	31.7	2.6	194.8

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2j

SCENARIO: BASE CASE
REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--SULPHUR DIOXIDE
(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	0	103	40	18	282	0	242	49	734
1991	0	128	55	0	240	0	352	49	823
1994	0	147	63	0	175	0	290	49	724
1997	0	148	69	25	164	0	290	49	766
2000	0	189	88	54	156	0	290	49	818
2003	0	207	80	81	121	0	290	49	828
2006	0	228	84	88	142	0	290	49	882
2009	0	251	89	92	129	0	290	49	900

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.2k

SCENARIO: BASE CASE
REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--NITROGEN OXIDES
(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	4	105	25	6	91	0	47	5	283
1991	4	127	34	0	85	0	40	5	315
1994	4	144	38	0	40	0	68	5	298
1997	4	159	42	9	40	0	69	5	328
2000	4	174	49	19	40	0	70	5	360
2003	4	188	48	29	28	0	70	5	371
2006	4	203	51	31	40	0	70	5	403
2009	4	219	53	33	40	0	70	5	423

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

D.3 CONSERVATION AND DEMAND-SIDE MANAGEMENT CASE

TABLE D.3a

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN BRITISH COLUMBIA (gigawatts)

	1988	2000	2009
Existing Hydro	10.85	11.92	12.47
Existing Gas Fired	0.90	0.90	0.90
Existing Combustion Turbine	0.17	0.31	0.31
New Hydro - Site 1			
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			0.04

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3b

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN ALBERTA (gigawatts)

	1988	2000	2009
Existing Hydro	0.73	0.73	0.73
Existing Pulverized Coal (Low Sulphur)	4.87	6.16	6.16
Existing Gas Fired	1.40	1.40	1.40
Existing Combustion Turbine	0.57	0.57	0.57
New Hydro - Site 1			
New Pulverized Coal (Low Sulphur)		0.52	1.78
New Combustion Turbine		0.01	0.10

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3c

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN SASKATCHEWAN

(gigawatts)

	1988	2000	2009
Existing Hydro	0.84	0.84	0.84
Eisting Pulverized Coal (Low Sulphur)	1.52	1.83	1.83
Existing Gas Fired	0.27	0.27	0.27
Existing Combustion Turbine	0.16	0.16	0.16
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine		0.06	0.15

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3d

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN MANITOBA

(gigawatts)

	1988	2000	2009
Existing Hydro	3.64	5.04	5.04
Existing Pulverized Coal (Low Sulphur)	0.37	0.37	0.37
Existing Combustion Turbine	0.06	0.06	0.06
New Hydro - Site 1			
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine	0.41	0.67	1.33

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3e

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN ONTARIO
(gigawatts)

	1988	2000	2009
Existing Hydro	7.81	7.81	7.81
Existing Pulverized Coal (High Sulphur)	10.65	10.65	10.65
Existing Gas Fired	0.45	0.45	0.45
Existing Combustion Turbine	0.63	0.63	0.63
Existing Nuclear	10.64	14.16	14.16
Existing Oil Fired	2.53	2.53	2.53
New Hydro - Site 1			0.03
New Pulverized Coal (High Sulphur)			
New Combustion Turbine			

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3f

SCENARIO:CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN QUEBEC
(gigawatts)

	1988	2000	2009
Existing Hydro	31.40	32.46	32.46
Existing Nuclear	0.69	0.69	0.69
Existing Combustion Turbine	0.36	0.36	0.36
Existing Oil Fired	0.48	0.48	0.48
New Hydro - Site 1		1.14	1.88
New Hydro - Site 2		4.47	8.70
New Hydro - Site 3			
New Hydro - Site 4			
New Hydro - Site 5			
New Combustion Turbine		0.28	0.99

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3g

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND

(gigawatts)

	1988	2000	2009
Existing Hydro	1.28	1.28	1.28
Existing Pulverized Coal (High Sulphur)	1.48	1.78	1.78
Existing Oil Fired	1.96	1.96	1.96
Existing Nuclear	0.64	0.64	0.64
Existing Combustion Turbine	0.28	0.28	0.28
New Nuclear			
New Pulverized Coal (High Sulphur)			
New Combustion Turbine		0.91	1.15
New IGCC		0.32	1.17

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3h

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT MIX OF GENERATING TECHNOLOGIES IN LABRADOR AND NEWFOUNDLAND

(gigawatts)

	1988	2000	2009
Existing Hydro	1.24	1.24	1.24
Existing Oil Fired	0.51	0.51	0.51
Existing Combustion Turbine	0.25	0.25	0.25
New Hydro - Site 1			
New Combustion Turbine	0.12	0.37	0.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3i

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--CARBON DIOXIDE
(millions of tonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	2.9	35.0	8.4	3.0	29.7	0.0	11.7	2.6	93.2
1991	2.9	39.6	10.1	0.0	20.8	0.0	14.6	2.6	90.6
1994	2.9	43.4	11.0	0.0	12.8	0.0	16.8	2.6	89.5
1997	2.9	46.4	11.6	1.2	16.1	0.0	18.7	2.6	99.6
2000	2.9	48.9	12.8	5.0	16.4	0.0	20.2	2.6	109.0
2003	2.9	51.3	12.3	8.7	10.3	0.0	21.6	2.6	109.6
2006	2.9	53.8	12.5	9.1	20.8	0.0	23.0	2.6	124.4
2009	2.9	56.3	12.6	9.2	25.5	0.0	24.4	2.6	133.6

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3j

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--SULPHUR DIOXIDE
(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	0	103	40	18	282	0	242	49	734
1991	0	118	49	0	198	0	312	49	726
1994	0	131	54	0	122	0	290	49	644
1997	0	141	57	8	153	0	290	49	697
2000	0	153	63	30	156	0	290	49	743
2003	0	143	61	33	98	0	290	49	714
2006	0	174	62	56	173	0	290	49	805
2009	0	186	62	56	175	0	290	49	818

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.3k

SCENARIO: CONSERVATION AND DEMAND-SIDE MANAGEMENT REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--NITROGEN OXIDES

(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	4	105	25	6	91	0	47	5	283
1991	4	119	30	0	44	0	55	5	277
1994	4	130	33	0	39	0	62	5	273
1997	4	140	35	3	40	0	67	5	293
2000	4	148	36	11	40	0	68	5	314
2003	4	156	37	19	21	0	69	5	309
2006	4	163	38	20	40	0	70	5	339
2009	4	172	38	20	40	0	70	5	348

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

D.4 COAL TECHNOLOGY COST CASE

TABLE D.4a

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN BRITISH COLUMBIA (gigawatts)

	1988	2000	2009
Existing Hydro	10.85	11.92	12.47
Existing Gas Fired	0.90	0.90	0.90
Existing Combustion Turbine	0.17	0.31	0.31
New Hydro - Site 1		0.40	2.44
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)		0.67	0.93
New Combustion Turbine			

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Objective Function: 1,640,343 MM $Cdn 1989.

TABLE D.4b

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN ALBERTA (gigawatts)

	1988	2000	2009
Existing Hydro	0.73	0.73	0.73
Existing Pulverized Coal (Low Sulphur)	4.67	6.16	6.16
Existing Gas Fired	1.40	1.40	1.40
Existing Combustion Turbine	0.57	0.57	0.57
New Hydro - Site 1			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine		0.11	0.27
New IGCC		1.90	4.30

SOURCES: Alberta Research Council and Candian Energy Research Institute.

TABLE D.4c

SCENARIO: COAL TECHNOLOGY COST
MIX OF GENERATING TECHNOLOGIES IN SASKATCHEWAN
(gigawatts)

	1988	2000	2009
Existing Hydro	0.84	0.84	0.84
Existing Pulverized Coal (Low Sulphur)	1.53	1.83	1.83
Existing Gas Fired	0.27	0.27	0.27
Existing Combustion Turbine	0.16	0.16	0.16
New Pulverized Coal (Low Sulphur)			0.15
New Combustion Turbine		0.55	0.81

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4d

SCENARIO: COAL TECHNOLOGY COST
MIX OF GENERATING TECHNOLOGIES IN MANITOBA
(gigawatts)

	1988	2000	2009
Existing Hydro	3.64	5.04	5.04
Existing Pulverized Coal (Low Sulphur)	0.37	0.37	0.37
Existing Combustion Turbine	0.06	0.06	0.06
New Hydro - Site 1			0.05
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine	0.41	1.35	3.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4e

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN ONTARIO (gigawatts)

	1988	2000	2009
Existing Hydro	7.81	7.81	7.81
Existing Pulverized Coal (High Sulphur)	10.65	10.65	10.65
Existing Gas Fired	0.45	0.45	0.45
Existing Combustion Turbine	0.63	0.63	0.63
Existing Nuclear	10.64	14.16	14.16
Existing Oil Fired	2.53	2.53	2.53
New Hydro - Site 1			1.20
New Pulverized Coal (High Sulphur)			
New Nuclear			
New Comubstion Turbine			
New IGCC		4.03	8.12

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4f

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN QUEBEC (gigawatts)

	1988	2000	2009
Existing Hydro	31.40	32.46	32.46
Existing Nuclear	0.69	0.69	0.69
Existing Combustion Turbine	0.36	0.36	0.36
Existing Oil Fired	0.48	0.48	0.48
New Hydro - Site 1		4.74	7.20
New Hydro - Site 2		6.39	8.70
New Hydro - Site 3			1.80
New Hydro - Site 4			0.75
New Hydro - Site 5			
New Nuclear			
New Combustion Turbine		1.79	1.79

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4g

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND (gigawatts)

	1988	2000	2009
Existing Hydro	1.28	1.28	1.28
Existing Pulverized Coal (High Sulphur)	1.48	1.78	1.78
Existing Oil Fired	1.96	1.96	1.96
Existing Nuclear	0.64	0.64	0.64
Existing Combustion Turbine	0.28	0.28	0.28
New Nuclear			
New Pulverized Coal (High Sulphur)			
New Combustion Turbine		1.14	1.58
New IGCC		1.12	2.64

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4h

SCENARIO: COAL TECHNOLOGY COST MIX OF GENERATING TECHNOLOGIES IN LABRADOR AND NEWFOUNDLAND (gigawatts)

	1988	2000	2009
Existing Hydro	1.24	1.24	1.24
Existing Oil Fired	0.51	0.51	0.51
Existing Combustion Turbine	0.25	0.25	0.25
New Hydro - Site 1		0.35	2.32
New Combustion Turbine	0.12	2.97	2.97

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4i

SCENARIO: COAL TECHNOLOGY COST
REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--CARBON DIOXIDE
(millions of tonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	2.9	35.0	8.4	3.0	29.7	0.0	11.7	2.6	93.2
1991	2.9	42.4	11.2	0.0	29.7	0.0	16.2	2.6	105.0
1994	2.9	47.7	12.7	0.0	25.9	0.0	19.2	2.6	111.0
1997	2.9	52.2	13.9	4.2	32.5	0.0	21.7	2.6	129.9
2000	2.9	56.6	16.0	8.8	37.5	0.0	24.2	2.6	148.4
2003	2.9	60.6	15.9	13.2	33.2	0.0	26.5	2.6	154.9
2006	2.9	65.1	16.8	14.5	46.2	0.0	29.0	2.6	176.9
2009	2.9	70.1	17.5	15.0	54.0	0.0	31.7	2.6	193.8

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4j

SCENARIO: COAL TECHNOLOGY COST
REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--SULPHUR DIOXIDE
(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	0	103	40	18	282	0	242	49	734
1991	0	128	55	0	240	0	352	49	823
1994	0	140	63	0	175	0	290	49	717
1997	0	143	69	25	164	0	290	49	741
2000	0	145	80	34	156	0	290	49	774
2003	0	147	80	81	121	0	290	49	768
2006	0	150	84	88	142	0	290	49	804
2009	0	153	89	92	129	0	290	49	901

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.4k

SCENARIO: COAL TECHNOLOGY COST REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--NITROGEN OXIDES
(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	4	105	25	6	91	0	47	5	283
1991	4	127	34	0	85	0	60	5	315
1994	4	139	38	0	40	0	68	5	293
1997	4	141	42	9	40	0	69	5	310
2000	4	144	48	19	40	0	70	5	329
2003	4	146	48	29	28	0	70	5	329
2006	4	148	51	31	40	0	70	5	348
2009	4	150	53	33	40	0	70	5	355

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

D.5 EFFICIENCY IMPROVEMENTS CASE

TABLE D.5a

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN BRITISH COLUMBIA
(gigawatts)

	1988	2000	2009
Existing Hydro	10.86	11.92	12.47
Existing Gas Fired	0.90	0.90	0.90
Existing Combustion Turbine	0.17	0.31	0.31
New Hydro - Site 1		0.46	2.44
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)		0.67	0.93
New Combustion Turbine			

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Objective Function: 1,639,764 MM $Cdn. 1988.

TABLE D.5b

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN ALBERTA
(gigawatts)

	1988	2000	2009
Existing Hydro	0.73	0.73	0.73
Existing Pulverized Coal (Low Sulphur)	4.87	6.16	6.16
Existing Gas Fired	1.40	1.40	1.40
Existing Combustion Turbine	0.57	0.57	0.57
New Hydro - Site 1			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine		0.11	0.27
New IGCC		1.90	4.29

SOURCES: Alberta Research Council and Candian Energy Research Institute

TABLE D.5c

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN SASKATCHEWAN
(gigawatts)

	1988	2000	2009
Existing Hydro	0.84	0.84	0.84
Existing Pulverized Coal (Low Sulphur)	1.53	1.83	1.83
Existing Gas Fired	0.27	0.27	0.27
Existing Combustion Turbine	0.16	0.16	0.16
New Pulverized Coal (Low Sulphur)			0.15
New Combustion Turbine		0.55	0.81

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5d

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN MANITOBA
(gigawatts)

	1988	2000	2009
Existing Hydro	3.64	5.04	5.04
Existing Pulverized Coal (Low Sulphur)	0.37	0.37	0.37
Existing Combustion Turbine	0.06	0.06	0.06
New Hydro - Site 1			0.09
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine	0.41	1.35	3.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5e

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN ONTARIO (gigawatts)

	1988	2000	2009
Existing Hydro	7.81	7.81	7.81
Existing Pulverized Coal (High Sulphur)	10.65	10.65	10.65
Existing Gas Fired	0.45	0.45	0.45
Existing Combustion Turbine	0.63	0.63	0.63
Existing Nuclear	10.64	14.16	14.16
Existing Oil Fired	2.53	2.53	2.53
New Hydro - Site 1			0.91
New Pulverized Coal (High Sulphur)			
New Nuclear			
New Comubstion Turbine			
New IGCC		3.41	7.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5f

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN QUEBEC (gigawatts)

	1988	2000	2009
Existing Hydro	31.40	32.46	32.46
Existing Nuclear	0.69	0.69	0.69
Existing Combustion Turbine	0.36	0.36	0.36
Existing Oil Fired	0.48	0.48	0.48
New Hydro - Site 1		4.74	7.20
New Hydro - Site 2		6.89	8.70
New Hydro - Site 3			1.80
New Hydro - Site 4			0.75
New Hydro - Site 5			
New Nuclear			
New Combustion Turbine		1.79	1.79

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5g

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND

(gigawatts)

	1988	2000	2009
Existing Hydro	1.28	1.28	1.28
Existing Pulverized Coal (High Sulphur)	1.48	1.78	1.78
Existing Oil Fired	1.96	1.96	1.96
Existing Nuclear	0.64	0.64	0.64
Existing Combustion Turbine	0.28	0.28	0.28
New Nuclear			
New Pulverized Coal (High Sulphur)			
New Combustion Turbine		1.14	1.65
New IGCC		1.12	2.11
New AFBC			
New PFBC			0.47

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5h

SCENARIO: EFFICIENCY IMPROVEMENTS MIX OF GENERATING TECHNOLOGIES IN LABRADOR AND NEWFOUNDLAND

(gigawatts)

	1988	2000	2009
Existing Hydro	1.24	1.24	1.24
Existing Oil Fired	0.51	0.51	0.51
Existing Combustion Turbine	0.25	0.25	0.25
New Hydro - Site 1		0.35	2.32
New Combustion Turbine	0.12	2.85	2.85

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5i

SCENARIO: EFFICIENCY IMPROVEMENTS REGIONAL DISTRIBUTION OF EMISSIONS--CARBON DIOXIDE

(millions of tonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	2.9	35.0	8.4	3.0	29.7	0.0	11.7	2.6	93.2
1991	2.9	42.4	11.2	0.0	30.3	0.0	16.2	2.6	105.4
1994	2.9	47.3	12.7	0.0	25.8	0.0	19.1	2.6	110.4
1997	2.9	50.9	13.9	4.2	30.9	0.0	21.1	2.6	126.4
2000	2.9	54.4	14.0	8.8	34.8	0.0	23.0	2.6	142.3
2003	2.9	57.6	15.9	13.2	31.8	0.0	25.1	2.6	149.0
2006	2.9	61.1	16.8	14.5	42.3	0.0	27.2	2.6	167.2
2009	2.9	65.0	17.5	15.0	48.3	0.0	29.3	2.6	180.7

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5j

SCENARIO: EFFICIENCY IMPROVEMENTS REGIONAL DISTRIBUTION OF EMISSIONS--SULPHUR DIOXIDE

(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	0	103	40	18	282	0	242	49	734
1991	0	128	55	0	240	0	352	49	823
1994	0	140	63	0	175	0	290	49	717
1997	0	142	49	25	169	0	290	49	744
2000	0	144	80	54	163	0	290	49	779
2003	0	146	80	81	134	0	290	49	779
2006	0	148	84	88	150	0	290	49	810
2009	0	150	89	92	141	0	290	49	810

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.5k

SCENARIO: EFFICIENCY IMPROVEMENTS REGIONAL DISTRIBUTION OF EMISSIONS--NITROGEN OXIDES

(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	4	105	25	6	91	0	47	5	283
1991	4	127	34	0	93	0	60	5	323
1994	4	139	38	0	40	0	47	5	293
1997	4	141	42	9	40	0	69	5	309
2000	4	143	48	19	40	0	70	5	328
2003	4	144	48	29	31	0	70	5	330
2006	4	146	51	31	40	0	70	5	346
2009	4	148	53	33	40	0	70	5	352

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

D.6 NUCLEAR POWER CASE

TABLE D.6a

SCENARIO: NUCLEAR POWER MIX OF GENERATING TECHNOLOGIES IN BRITISH COLUMBIA

(gigawatts)

	1988	2000	2009
Existing Hydro	10.85	11.92	12.47
Existing Gas Fired	0.90	0.90	0.90
Existing Combustion Turbine	0.17	0.31	0.31
New Hydro - Site 1		0.40	2.44
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)		0.67	0.93
New Combustion Turbine			

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Objective Function: 1,639,481 MM $Cdn. 1988.

TABLE D.6b

SCENARIO: NUCLEAR POWER MIX OF GENERATING TECHNOLOGIES IN ALBERTA

(gigawatts)

	1988	2000	2009
Existing Hydro	0.73	0.73	0.73
Existing Pulverized Coal (Low Sulphur)	4.87	6.16	6.16
Existing Gas Fired	1.40	1.40	1.40
Existing Combustion Turbine	0.57	0.57	0.57
New Hydro - Site 1			
New Pulverized Coal (Low Sulphur)		1.90	4.30
New Combustion Turbine		0.11	0.27

SOURCES: Alberta Research Council and Candian Energy Research Institute

TABLE D.6c

SCENARIO: NUCLEAR POWER
MIX OF GENERATING TECHNOLOGIES IN SASKATCHEWAN
(gigawatts)

	1988	2000	2009
Existing Hydro	0.84	0.84	0.84
Existing Pulverized Coal (Low Sulphur)	1.53	1.83	1.83
Existing Gas Fired	0.27	0.27	0.27
Existing Combustion Turbine	0.16	0.16	0.16
New Pulverized Coal (Low Sulphur)			0.15
New Combustion Turbine		0.55	0.81

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6d

SCENARIO: NUCLEAR POWER
MIX OF GENERATING TECHNOLOGIES IN MANITOBA
(gigawatts)

	1988	2000	2009
Existing Hydro	3.64	5.04	5.04
Existing Pulverized Coal (Low Sulphur)	0.37	0.37	0.37
Existing Combustion Turbine	0.06	0.06	0.06
New Hydro - Site 1			0.09
New Hydro - Site 2			
New Pulverized Coal (Low Sulphur)			
New Combustion Turbine	0.41	1.35	3.62

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6e

SCENARIO: NUCLEAR POWER
MIX OF GENERATING TECHNOLOGIES
IN ONTARIO
(gigawatts)

	1988	2000	2009
Existing Hydro	7.81	7.81	7.81
Existing Pulverized Coal (High Sulphur)	10.65	10.65	10.65
Existing Gas Fired	0.45	0.45	0.45
Existing Combustion Turbine	0.63	0.63	0.63
Existing Nuclear	10.64	14.16	14.16
Existing Oil Fired	2.53	2.53	2.53
New Hydro - Site 1			0.80
New Pulverized Coal (High Sulphur)		0.02	0.05
New Nuclear		2.18	4.70
New Comubstion Turbine			
New IGCC			0.30

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6f

SCENARIO: NUCLEAR POWER
MIX OF GENERATING TECHNOLOGIES
IN QUEBEC
(gigawatts)

	1988	2000	2009
Existing Hydro	31.40	32.46	52.46
Existing Nuclear	0.69	0.69	0.69
Existing Combustion Turbine	0.36	0.36	0.36
EOF	0.48	0.48	0.48
New Hydro - Site 1		4.74	7.20
New Hydro - Site 2		6.39	8.70
New Hydro - Site 3			1.80
New Hydro - Site 4			0.75
New Hydro - Site 5			
New Nuclear			
New Combustion Turbine		1.79	1.79

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6g

SCENARIO: NUCLEAR POWER MIX OF GENERATING TECHNOLOGIES IN NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND (gigawatts)

	1988	2000	2009
Existing Hydro	1.28	1.28	1.28
Existing Pulverized Coal (High Sulphur)	1.48	1.78	1.78
Existing Oil Fired	1.96	1.96	1.96
Existing Nuclear	0.64	0.64	0.64
Existing Combustion Turbine	0.28	0.28	0.28
New Nuclear			
New Pulverized Coal (High Sulphur)			
New Combustion Turbine		1.14	1.58
New IGCC		1.12	2.64

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6h

SCENARIO: NUCLEAR POWER MIX OF GENERATING TECHNOLOGIES IN LABRADOR AND NEWFOUNDLAND (gigawatts)

	1988	2000	2009
Existing Hydro	1.24	1.24	1.24
Existing Oil Fired	0.51	0.57	0.57
Existing Combustion Turbine	0.25	0.25	0.25
New Hydro - Site 1		0.35	2.32
New Combustion Turbine	0.12	3.37	3.37

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6i

SCENARIO: NUCLEAR POWER REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--CARBON DIOXIDE

(millions of tonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	2.9	35.0	8.4	3.0	29.7	0.0	11.7	2.6	93.2
1991	2.9	42.4	11.2	0.0	30.5	0.0	16.2	2.6	105.8
1994	2.9	47.8	12.7	0.0	27.0	0.0	19.2	2.6	112.1
1997	2.9	52.5	13.9	4.2	27.0	0.0	21.7	2.6	124.7
2000	2.9	57.0	16.0	8.8	27.0	0.0	24.2	2.6	138.4
2003	2.9	61.2	15.9	13.2	23.9	0.0	26.5	2.6	146.2
2006	2.9	65.9	16.8	14.5	31.0	0.0	29.0	2.6	162.5
2009	2.9	71.1	17.5	15.0	32.3	0.0	31.7	2.6	173.1

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6j

SCENARIO: NUCLEAR POWER REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--SULPHUR DIOXIDE

(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	0	103	40	18	282	0	242	49	734
1991	0	128	55	0	240	0	352	49	823
1994	0	147	63	0	175	0	290	49	724
1997	0	162	69	25	175	0	290	49	777
2000	0	189	80	54	175	0	290	49	836
2003	0	207	80	81	146	0	290	49	853
2006	0	228	84	88	175	0	290	49	915
2009	0	251	89	92	175	0	290	49	946

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE D.6k

SCENARIO: NUCLEAR POWER REGIONAL DISTRIBUTION OF UTILITY EMISSIONS--NITROGEN OXIDES

(kilotonnes per year)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.	Total
1988	4	105	25	6	91	0	47	5	283
1991	4	127	34	0	94	0	60	5	323
1994	4	144	38	0	40	0	68	5	298
1997	4	159	42	9	40	0	69	5	328
2000	4	174	48	19	40	0	70	5	360
2003	4	188	48	29	30	0	70	5	373
2006	4	203	51	31	40	0	70	5	403
2009	4	219	53	33	40	0	70	5	423

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

APPENDIX E

GLOSSARY

Appendix E

GLOSSARY

ACID: A concentration of hydrogen ions (H+) in solution. Acidity is expressed on a numerical pH scale. An acidic solution has a pH less than 7.0.

ACIDIC DEPOSITION: The transfer of acidic or acidifying materials from the atmosphere by dry and wet deposition of the earth.

ACID RAIN: A general term describing precipitation in any form that has been acidified by the presence of atmospheric pollutants, primarily the oxides of sulphur and nitrogen.

ACID RAIN PRECURSOR: A material such as SO_2 or NO_x which is transformed in the atmosphere to become a component of acid rain.

AEROSOL: A suspension of liquid or solid particles in a gas.

ALKALINITY: A measure of water's ability to neutralize added acids by the reaction of hydrogen ions with carbonate, bicarbonate, and hydroxide ions.

ALTERNATING CURRENT: An electric current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles per second; such electricity is said to have a frequency of 60 hertz. Alternating current is used in almost all aspects of power systems because it can be transmitted and distributed much more economically than direct current.

ALTERNATIVE ENERGY/TECHNOLOGY: Energy sources or technologies which are not yet widely used, as opposed to "conventional" energy/technology. The term usually refers to renewable energy sources and small, decentralized installations. Examples are photovoltaics, solar heating, wind power and waste-fuelled electrical generation.

ARTIFICIALLY-FIXED NITROGEN: Traditional farmers intervene in the nitrogen cycle by cultivating legumes interspersed with other crops, or in rotation with them, plowing legumes under as green manure and by recycling biomass such as crop residues and animal and human wastes. Modern agriculture retains some of these practices, but the total mass of recycled organic nitrogen is now dwarfed by industrial production of nitrogen fertilizers from atmospheric nitrogen. Synthetic ammonia production has grown exponentially since its commercialization in the early 1920s.

Synthetic ammonia is used directly as a cheap, highly concentrated fertilizer or converted to urea, nitrates, or compound fertilizers (combinations of nitrogen with phosphate, potassium, and micronutrient elements).

When excess nitrogen fertilizer is applied to a field, the levels of nitrate in the runoff and nitrous oxide in the atmosphere increase. Nitrous oxide levels are enhanced because nitrification and denitrification, which convert nitrogen fertilizers and biomass to nitrous oxide and then to nitrogen gas, sometimes stop with the production of nitrous oxide. When farmers fertilize or over-fertilize crops with synthetic nitrogen fertilizers produced from nitrogen gas, they essentially withdraw nitrogen from the atmosphere in its stable molecular form and return some of it as nitrous oxide, a compound that has important environmental impacts.

AVOIDED COST: The cost which would be incurred by an electric utility in providing new generating capacity if the utility were to provide the power itself instead of purchasing it from an independent generator.

BASE: The opposite of acid; depends on the concentration of hydroxyl ions (OH-) in solution. A basic alkaline solution has a pH greater than 7.0.

BASE LOAD: The minimum continuous load over a given period of time.

BASE-LOAD GENERATING STATION: A generating station which is normally operated to supply all or part of the base load of a system and which consequently operates at full output whenever available. Base-load generating units tend to be large units with low operating costs.

BUFFER: A chemical which, in solution, will resist changes in pH or, if added to a solution, will change the pH of that solution. In nature, limestone (calcium carbonate) will act as a buffer against Acid Rain to maintain or raise the pH of a waterbody.

CANDU: A Canadian-designed nuclear ractor. The name stands for "CANadian Deuterium Uranium" steam generating system. All nuclear generating stations produce steam from atomic fission to drive turbines and make electricity. CANDU uses deuterium, "heavy water," rather than ordinary light water, as an essential component of the reactor. CANDU also uses natural rather than enriched uranium as fuel.

CARBON DIOXIDE: Emissions caused by natural and human factors. Volcanoes emit carbon dioxide, and major changes in global vegetation can contribute to, or withdraw from, the atmospheric carbon reservoir. Combustion of fossil fuels adds carbon to the atmosphere, as do gas flaring and cement production. In addition, carbon is released by the burning or decomposition of the biomass when forestland is cleared.

CAPABILITY: The maximum load that a station or equipment is capable of carrying under specified conditions.

CAPACITY: The rate of delivery of energy (for example, a utility might sell 50 megawatts of capacity or electric power) or the maximum quantity of power that a piece of equipment or a system is capable of carrying or supplying (for example, a generating unit might have a rated capacity of 50 megawatts).

CAPACITY FACTOR: For any equipment, the ratio of the average load during some period of time to the rated capacity of the equipment. Capacity factor is usually expressed as a percentage.

CHLOROFLUOROCARBONS: Chlorofluorocarbons (CFCs), in the form of CFC-11, CFC-12, and CFC-113, affect the climate through their absorption of infrared radiation and their reaction in the atmosphere with other chemicals. The CFCs produce a highly reactive form of chlorine, which in turn depletes the stratospheric ozone layer. In Canada, almost 70 percent of CFCs are used in air conditioning and rigid foam insulation.

On July 1, 1989, Environment Canada introduced regulations that will reduce the use of CFCs in Canada to 50 percent of their 1986 levels by 1999. In light of recent information regarding the impact of CFCs on the ozone layer, further reductions are being examined.

CIRCUIT: Any conductor or set of conductors intended to carry electricity.

CIRCUIT BREAKER: A switching device to open or close an electric power circuit during either normal system operation or fault conditions.

COAL GASIFICATION: A chemical process which converts coal to a gaseous fuel suitable for burning in fossil generating stations.

COGENERATION: The combined production of electricity and useful heat (usually steam).

COMMON POLLUTANT: Pollutants historically regarded as being the most significant air pollutants and are known as the criteria pollutants at U.S. EPA (Particulates, SO_2, NO_x, CO).

CONSUMPTION: Use of electrical energy, typically measured in kilowatt-hours.

CONVENTIONAL GENERATION: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

CONVERTER STATION: An installation for converting direct current into alternating current, or for changing one frequency of alternating current to another.

CURRENT: The flow of electricity in a conductor. Current is measured in amperes.

DEMAND: "Demand" is often used synonymously with "power" which is the rate at which electrical energy is being delivered.

DEMAND CHARGE: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used. The other component of the two-part price is the energy charge.

DEMAND MANAGEMENT: A set of programs and measures undertaken by electrical utilities to influence the amount and timing of customer demand for electricity. Some programs, like electrical efficiency improvements, are designed to reduce demand. Others, like time-of-use rates, are designed to shift consumption from peak to off-peak periods.

DEPENDABLE CAPACITY: The load-carrying ability of a station or system under adverse conditions, as for example, the capacity of a hydroelectric station under defined low-flow conditions.

DIRECT CURRENT: Current that flows continuously in one direction (as opposed to an alternating current). The current supplied from a battery is direct current.

DIRECT CURRENT TRANSMISSION: Transmission of electricity by direct current (DC) instead of the usual alternating current. Direct current has certain advantages for long-distance, point-to-point transmission and for interconnecting power systems that would otherwise be unstable if an attempt were made to tie them together by alternating current transmission. There are four high-voltage DC installations in service in Canada: (1) the Vancouver Island underwater transmission link; (2) the Nelson River (Manitoba) overhead transmission line; (3) the Eel River (New Brunswick) asynchronous tie; and (4) the Chateauguay (Quebec) asynchronous tie.

DISTRIBUTION SYSTEM: The lines, transformers, switches, etc. used to distribute electricity over short distances from the transmission system to customers. Distribution generally takes place at relatively low voltages (44 kilovolts and less).

DRY DEPOSITION: A process whereby particles such as fly ash, sulphates and nitrates, and gases such as sulphur dioxide and nitric oxide are deposited on, or absorbed onto, surfaces. The dry particles or gases can be converted into acids after deposition through contact with water.

ELECTRICAL EFFICIENCY IMPROVEMENTS: Measures designed to reduce the consumption of electricity while maintaining a given level of service. For example, a less efficient bulb may be replaced with a more efficient bulb which gives off the same amount of light while consuming less electricity. Also referred to as conservation measures.

ELECTRICAL POWER: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

ELECTRICAL UTILITY: An organization that has as its prime purpose the generation, transmission and/or distribution of electric energy for sale.

ELECTRO-TECHNOLOGY: A technology that uses electricity in its processes, especially new technologies used to displace other energy sources. An example is the use of electrically-driven heat pumps for kiln drying wood, in place of air heated by on-site fuel combustion.

EMISSION FACTOR: An estimate or statistical average of the rate at which a contaminant is released to the atmosphere as a result of some activity, such as combustion or industrial production, divided by the level of that activity. The emission factor, therefore, relates the average quantity of each contaminant emitted to an appropriate base quantity. It is usually expressed as the weight of contaminant divided by a unit weight, volume, distance or duration of the associated activity that emits the pollutants (e.g., kg of SO_2 emitted per tonne of coal combusted). Factors are usually obtained from data of varying degrees of accuracy and may be presented for either uncontrolled surfaces or facilities having air pollution control devices in place.

ENERGY CHARGE: The component of a two-part price for electricity that is based on the amount of energy taken. The other component of price is the demand charge.

ENERGY SOURCE: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

EPA: United States Environmental Protection Agency.

FIRM ENERGY OR POWER: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

FLUIDIZED-BED COMBUSTION: A method of combustion in which air, blown up through orifices in the floor of the firebox, suspends particles as a fluidized bed. The particles consist of fuel and a sorbent such as limestone.

FUGITIVE EMISSIONS: Air pollution deriving from human activities that do not emanate from a particular point, such as an exhaust pipe or stack. Roadway dust and VOC from refinery valves are examples.

GENERATING STATION: A station comprising one or more generating units for the production of electricity. The main types of generating stations are hydroelectric, nuclear-electric and fossil-fuelled (by coal, oil or natural gas). In some parts of the world, such as the Geysers region of California, geothermal-electric power is becoming an important element of generating capacity.

GENERATING UNIT: An electric generator, the prime mover that drives the generator, and all the associated equipment that must be operated together as a group to generate electricity. A generating unit can usually operate independently of other units at a multi-unit station.

GIGAWATT (GW): One billion watts. (See Watt.)

GIGAWATT HOUR (GW.h): A unit of bulk energy. A million kilowatt-hours. A billion watt hours.

GREENHOUSE GAS EMISSIONS: Gases like carbon dioxide (CO_2) and methane trap heat in the earth's atmosphere and are believed to contribute to global warming, the so-called "greenhouse effect."

GRID: A network of electric power lines and connections.

HEAD (HYDRAULIC): The difference in elevation between the water level immediately above a hydroelectric generating station and the water level immediately below it. The power output of the station is proportional to the hydraulic head.

HEAT RATE: A measure of generating station thermal efficiency, generally expressed as British thermal units per net kilowatt-hour. It is computed by dividing the total heat (Btu) content of the fuel burned by the resulting net kilowatt-hours of electricity generated. In metric units, the heat rate is expressed as kilojoules per kilowatt-hour.

HEAT VALUE: Low and High Heat Values. Any fuel containing hydrogen yields water as one product of combustion. At atmospheric pressure, the partial pressure of the water vapor in the resulting combustion gas mixture will usually be sufficiently high to cause water to condense out if the temperature is allowed to fall below 120 to 140 F. This causes liberation of the heat of vaporization of any water condensed. The low heat value is evaluated assuming no water vapor condensed, whereas the high heat value is calculated assuming all water vapor condensed.

To facilitate calculations of the temperature attained by combustion, it is desirable to make use of the low heat value. The necessity of taking into account the heat of vaporization of the water vapor and the difference between the specific heats of liquid water and of water vapor is thus avoided. The high heat combustion exceeds the low heat of combustion by the difference between the heat actually given up on cooling the products to the initial temperature and that which would have been given up if the products had remained in the gaseous state. The quantity to be subtracted from the high heat value to obtain the low heat value will vary with the composition of the fuel.

HYDROELECTRIC STATION: An electric generating station in which the prime movers are hydraulic turbines.

INCREMENTAL GENERATING COST: The cost of generating one additional unit of electric energy above some previously determined base quantity.

INDEPENDENT (PRIVATE) GENERATION: Generation owned or operated by producers other than a utility. These producers usually have generating plants for the purpose of supplying electric power required in their own industrial and commercial operations. The term also covers private plants whose sole purpose is the sale of electricity to a utility.

INSTALLED (GENERATING) CAPACITY: The capacity measured at the output terminals of all the generating units in a station, before deduction of station service requirements.

INTEGRATED PLANNING: Joint planning by different power systems in order to minimize total costs. Integrated planning is one characteristic of a true power pool.

INTERCONNECTION AGREEMENT: An agreement made between two power utilities to govern the operation of interconnections between their systems. Typically such an agreement defines different classes of inter-utility electricity transfers and specifies how they shall be priced between the two companies.

INTERCONNECTED SYSTEM: A system consisting of two or more individual power systems connected together by tie lines.

INTERRUPTIBLE ENERGY OR POWER: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

INTER-UTILITY TRANSFER: A transfer of electric power between two or more electrical utilities. The NEB Part VI Regulations define five classes of inter-utility transfer. These are:

(1) Adjustment transfer: A transfer of electric power or energy made: (a) to adjust an energy account balance; (b) to compensate for electrical losses; (c) to compensate for services rendered; (d) to deliver output entitlements; or (e) to provide upstream or downstream benefits.

(2) Carrier transfer: A transfer of electric power or energy by one utility over the circuits of another, for delivery either to a third party or back to the originating utility.

(3) Equichange transfer: An interchange of equal quantities of electric power or energy within a stated period.

(4) Sale transfer: A transfer of electric power or energy under a contract of sale.

(5) Storage transfer: An electric energy transfer "banked" for the time being in the form of water in the reservoir space of another electrical utility, in the expectation that equivalent electric energy will be returned at a later time.

ISOLATED SYSTEM: An electric power system not interconnected with any other system (such as the Northern Canada Power Commission). Isolated systems are usually of relatively small capacity.

JOULE: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt-hour.

KILOVOLT (kV): 1000 volts.

KILOWATT (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

KILOWATT-HOUR (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt-hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt-hour is equal to 3.6 million joules.

LEACHING: A natural process by which water dissolves minerals out of rocks. The leaching of heavy metals, such as mercury, into water supplies is believed to be a serious consequence of Acid Rain.

LIMESTONE: A sedimentary rock consisting chiefly of calcium carbonate. Limestone is an effective buffer against acid rain.

LOAD: The amount of electric power or energy consumed by a particular customer or group of customers.

LOAD FACTOR: The ratio of the average load during a designated period to the peak or maximum load in that same period, usually expressed as a percentage of the peak load.

LOAD MANAGEMENT: The manipulation of customer demand by economic and/or technical means.

LOAD REJECTION (LOAD SHEDDING): Interrupting the supply of electricity to a selected region or group of customers as a means of preserving the continuing safe operation of the remainder of a power system. This action is sometimes taken in an emergency when the total system load exceeds the capacity of the generation available to supply it.

LOAD SHAPE: A consistent pattern of rising or falling customer demand over a period of time. Load or demand has a typical daily, weekly and seasonal shape, determined by prevailing weather conditions and social patterns such as hours of sleeping, waking and working.

LOAD SHIFTING: A demand management technique which encourages customers to shift electrical load or consumption from peak to off-peak hours. Load shifting reduces the need for generating facilities and permits the use of lower cost fuels.

LOSSES: Energy or power lost in circuits or equipment, mainly in the form of heat, when current flows through the circuit.

MEGAWATT (MW): a unit of bulk power; 1000 kilowatts.

MEGAWATT HOUR (MW.h): A unit of bulk energy; 1000 kilowatt-hours.

METHANE (CH_4): After carbon dioxide, methane is the second largest contributor to the greenhouse effect. Most methane emissions are generated by natural sources such as decomposition of materials in wetlands and by non-energy-related human activities such as agriculture and animal husbandry. The production and use of energy account for only a limited share of methane emissions.

MILL: 1/1000 of a dollar.

MOBILE SOURCE: A segment of the area source classification representing transportation sources such as vehicles, aircraft and railroads.

NATIONAL AMBIENT AIR QUALITY OBJECTIVES: Prescribed by the federal government under the *Canadian Environmental Protection Act* to reflect regional air quality goals in three ranges--"tolerable," "acceptable," and "desirable." They are not source-specific but are geographical area-specific. They are applicable to specific air contaminants. They are enforceable by the provinces once adopted by them as part of their environmental laws in virtue of a federal-provincial agreement under the federal *Canadian Environmental Protection Act*.

NITROUS OXIDE (N_2O): Combustion of fossil fuels releases nitrous oxide, which affects the formation of ozone in the troposphere. Data are not available on levels of nitrous oxide emissions from the combustion of different fossil fuels. The non-energy sources of nitrous oxide emissions such as the use of agricultural fertilizers are believed to be far larger than the energy-related sources. About one-third of total global N_2O emissions are anthropogenic, resulting mainly from fertilizer application and to a lesser extent from large stationary combustion sources. Mobile Sources are not significant emittors of N_2O.

NONFERROUS SMELTING: The smelting, roasting, and sintering of sulphur-containing ores, such as those containing copper or nickel, and scrap materials.

NUCLEAR FUEL: A substance containing one or more fissile nuclides capable of maintaining a chain reaction in a reactor. The term may also be used to include a substance containing one or more fertile nuclides that can be transmuted into such fissile nuclides.

NUCLEAR POWER: Power generated at a station where the steam to drive the turbines is produced by the process of atomic fission, rather than by burning a combustible fuel.

NUCLEAR (FISSION) REACTOR: A device in which a self-sustaining nuclear fission chain reaction can be maintained and controlled. The term "nuclear reactor" is sometimes applied to a device in which a nuclear fusion reaction can be produced and controlled (fusion reactor).

NUCLIDE: An individual atomic species. Deuterium and tritium, although they are both isotopes of hydrogen, are two different nuclides.

PARALLEL POWER: Independent generation which is linked to and synchronized with the bulk electricity system.

PARTICULATES: Or total particulate matter (TPM) is any aerosol that is released to the atmosphere in either solid or liquid form. The upper size limit is generally regarded to be about 75 microns.

PEAK DEMAND: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

PEAK PERIOD: Periods during which relatively high demands are placed on an electrical system, as opposed to off-peak periods.

PEAKING UNIT: A generating unit intended to be operated intermittently to supply peak loads.

pH SCALE: is used to measure acidity or alkalinity. Neutral solutions have a pH of 7, acid solutions have a pH less than 7, and alkaline solutions have a pH greater than 7. Each unit change in pH represents a tenfold change in acidity. For example, rainfall with pH 4 is 10 times as acidic as rainfall with pH 5 and 100 times as acidic as rainfall with pH 6.

POINT SOURCE: Any stationary source that usually releases emission through stacks at elevated heights for which individual source records are maintained in the inventory and for which annual emissions exceed a specified cut-off level. Although there is no uniform designated cut-off level, sources with emissions that generally exceed 100 metric tons (tonnes) per year of any one of the five common pollutants generally are included in inventories. Similarly, emission points that release greater than approximately 500 tonnes per year are regarded as major point sources.

POLLUTION RIGHTS: A system of marketable permits allowing the bearer to emit a specified level of pollutants. Under this rights system, the government controls the total level of emissions, but not the distribution of these emissions among firms.

POWER REACTOR: A nuclear reactor whose primary purpose is to produce energy. Reactors in this class include electric power reactors, heat-producing reactors (producing heat for industrial processing, to supply district heating systems, etc.) and propulsion reactors in nuclear-powered surface vessels and submarines.

POWER SYSTEM: All the interconnected facilities of an electrical utility. A power system includes the generating stations, transformers, switching stations, transmission lines, substations, distribution lines and circuits to the customers' premises; that is, all the facilities required to provide electrical services to the customers.

PRIMARY ENERGY SOURCE: The source of primary energy from which electricity is generated, including falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, biomass, direct solar radiation, geothermal energy and tidal energy.

PRIME MOVER: The turbine or engine that drives an electrical generator.

PUMPED STORAGE: An arrangement in which water is pumped from a lower to a higher reservoir, during off-peak hours. During peak hours, the water is allowed to return to the lower reservoir through hydroelectric turbines, thus generating power. Usually the turbines are reversible so that they can also serve as the pumps in the system.

QUALIFYING FACILITY (QF): Generating unit qualifying for special regulatory treatment under the Public Utility Regulatory Policies Act of 1978.

RADIOACTIVE WASTE: Unwanted radioactive materials obtained in the processing, handling or utilization of radioactive substances. Such wastes may be classified according to their degree of activity or to their half-lives, as follows.

A. According to the radionuclide contents:

high-level waste: the highly radioactive liquid separated during the chemical reprocessing of irradiated fuel; or irradiated reactor fuel if it is not foreseen that the spent fuel will be reprocessed; or any other waste with a comparable radioactivity level.

intermediate-level waste: waste of a lower radioactivity level than high-level waste, but which still requires shielding during handling.

low-level waste: waste which does not require shielding during normal handling because of its low radionuclide content.

B. According to the half-life of the radioactive waste:

long-lived waste: waste that will not decay to an acceptable activity level in a period of time during which administrative controls can be expected to last.

short-lived waste: waste which will decay to a level considered to be insignificant from a radiological viewpoint, in a time period during which administrative controls can be expected to last. In some jurisdictions, radionuclides with a half-life of less than 30 years are considered to fall into this category.

RADIOACTIVE WASTE MANAGEMENT: All activities, administrative and operational, that are involved in the handling, treatment, conditioning, transportation, storage and disposal of radioactive waste.

RADIOACTIVITY: The property of certain nuclides of spontaneously emitting particles or gamma radiation from their nucleus, of undergoing spontaneous fission, or of emitting X-radiation.

RELIABILITY: The ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers.

RENEWABLE ENERGY SOURCE: A source of energy which is inherently self-renewing, such as the various manifestations of solar energy (water power, biomass, wind energy, direct solar radiation, wave energy and ocean currents), tidal energy and geothermal energy.

RESERVE MARGIN: The difference between generating capacity and peak load, expressed as a percentage of peak load.

RESERVE (GENERATING) CAPACITY: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required for two main reasons: in case of the unexpected breakdown of generating equipment; and in case the actual peak load is higher than forecast.

RIGHT-OF-WAY: The strip of land on which a power line is located, and on which the power company has acquired the legal right to perform construction and maintenance, to restrict the growth of vegetation, and sometimes to restrict construction by other parties. The width of the right-of-way varies with line voltage.

RUN-OF-THE-RIVER PLANT: A hydroelectric generating station having negligible capacity for the storage of water, so that the plant has to run on the natural flow of the river. The output of the plant may therefore be subject to considerable variation.

SCHEDULED MAINTENANCE: Maintenance of equipment performed in accordance with a prearranged schedule.

SEASONAL DIVERSITY: The diversity between loads that reach their maximum values at different seasons of the year. For example, most Canadian power systems experience their annual peak loads in the winter, whereas many U.S. systems have their annual peaks in the summer because of air conditioning. Systems that differ in this way can effect economies of scale by exchanging energy on a seasonal basis.

SERVICE AREA: The area within which a utility is required, or has the right, to serve consumers.

SOCIAL BENEFITS: Benefits, whether tangible or intangible, resulting from a project. Social benefits are distinguishable from private benefits in that they include all the benefits of a project, whether or not they accrue to project sponsors.

SOCIAL COSTS: Costs or damages, whether tangible or intangible, which a project causes to be imposed. Social costs are distinguishable from private costs in that they include all the costs of a project incurred by all citizens rather than only those incurred by the project sponsors.

SORBENT: An additive used to enhance sulphur dioxide removal, e.g., limestone.

SPATIAL RESOLUTION: The reporting of emission data by geographic locations.

SPECIATION: Is the determination and reporting of specific elements or compounds that constitute pollutants such as: Particulates, Nitrogen Oxides and Volatile Organic Compounds.

SULPHUR DIOXIDE: A heavy, odourless, suffocating gas with the chemical formula SO_2. Sulphur dioxide is created by both natural and anthropogenic activities. Anthropogenic sources include fossil fuel combustion and industrial activities. High levels of sulfur dioxide and suspended particulate matter (SPM) may cause respiratory problems among adults and children and may also result in lower respiratory tract illness.

SUPERCONDUCTOR: An electrical conductor offering negligible resistance to the flow of electricity.

SUSPENDED PARTICULATE MATTER (SPM): Levels of SPM rise both from human and natural activities including combustion of wood and fossil fuels, industrial activities, and dust raised by vehicular traffic or wind. High SPM levels may aggravate respiratory illnesses.

TERAWATT HOURS (TW.h): One billion kilowatt-hours.

THC: Total Hydrocarbons include all volatile organic compounds that are released to the atmosphere.

THERMAL GENERATING STATION: An electric generating station where the prime movers are driven by gases or steam produced by burning fuels (such as coal, oil, gas, wood or refuse) or by nuclear processes.

THERMAL REACTOR: A reactor in which fission is induced predominantly by thermal or "slow" neutrons.

TIME-OF-USE (TIME-DIFFERENTIATED) RATES: Rates which vary based on the time of day, day of the week, or season of the year.

TON: Also known as a short ton, it contains 2,000 pounds. One ton equals 0.9072 tonne.

TONNE: A metric ton, or tonne, contains 1000 kilograms, or 2,204.623 pounds. One tonne equals 1.1023 tons.

TRANSFORMER: An electromagnetic device for raising or lowering the voltage of alternating current electricity.

TRANSMISSION LINE: A line used for the transmission of electric power at high voltage. Transmission lines may be constructed overhead, underwater or underground. Lines of voltage less than 115 kilovolts are usually considered to be subtransmission or distribution.

TRANSMISSION SYSTEM: Lines, transformers, switches, etc. used to transport electricity in bulk from sources of supply to other principal parts of the system. Transmission is generally at voltages of 115 kilovolts and above.

TURBINE (HYDRAULIC): A rotary type of prime mover in which mechanical energy is produced by the force of water, steam or gas directed against blades fastened to a rotating shaft.

VOC: Volatile Organic Compounds also known as Reactive Organic Gases (ROG) or Non-Methane Volatile Organic Compounds (N-MVOC) refer only to photochemically reactive hydrocarbons and therefore exclude compounds such as methane, ethane and several chlorinated organics.

VOLTAGE: The electrical force, measured in volts or multiples of volts (e.g. kilovolts), that causes a current to flow in a circuit. In North America, the standard voltage for residential use is 115 volts, with 230 volts used for heavy appliances such as ranges, dryers and hot water heaters. Voltages used for urban and rural distribution range from about 4 kV to 44 kV. The most common transmission voltages are 115, 132, 230, 345, 500 and 735 kV. The higher the voltage, the more power a transmission line can carry.

WATT:	The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.
WET DEPOSITION:	A process of precipitation whereby acidic chemicals, including dilute sulphuric and nitric acids and sulphates, are deposited in rain, snow, etc.
WHEELING:	The transmission of power belonging to one utility through the circuits of another utility, for delivery either to a third party or back to the originating system.

SOURCES: These definitions are taken from the House of Commons report, *Nuclear Energy: Unmasking the Mystery, August 1988*; World Resources Institute and International Institute for Environmental and Development, *World Resources 1988-89*; Energy, Mines and Resources Canada, *Electric Power in Canada 1988*; House of Commons report, *Report of the Special Committee on Acid Rain*; U.S. Congress, Office of Technology Assessment, *Electric Power: Wheeling and Dealing*; Environment Canada, The 1985 Canadian Emissions Inventory of Common Air Contaminants and Ontario Hydro, Providing the Balance of Power.

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